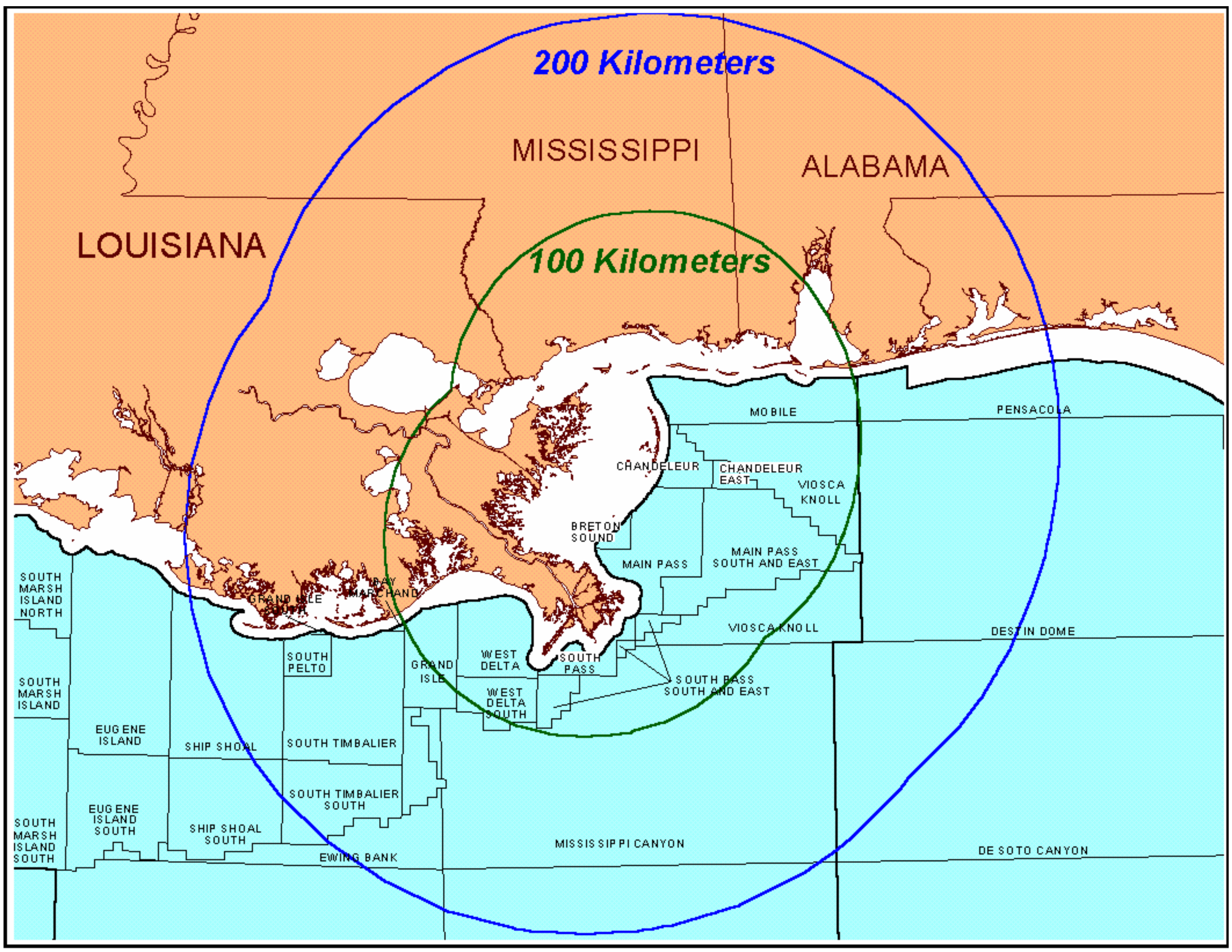
OCS Study
MMS 2002-073

Emission Inventories of OCS Production and Development Activities in the Gulf of Mexico

Final Report



U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

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Emission Inventories of OCS Production and Development Activities in the Gulf of Mexico

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LIST OF ABBREVIATIONS

BAMP	Breton Aerometric Monitoring Program
BNWA	Breton National Wildlife Area
BOADS	Breton Offshore Activities Data System for Air Quality
CD	compact disc
CO	carbon monoxide
CON	construction
DBMS	Database Management System
DMA	Marine Distillate fuel A
DMB	Marine Distillate fuel B
DRILL	drilling
EPA	U.S. Environmental Protection Agency
EQ	engines, turbines, and boilers
ESRI	Environmental Systems Research Institute, Inc.
FL	flares
FWS	Fish and Wildlife Service
GIS	Geographic Information System
GLY	glycol units
GMAQS	Gulf of Mexico Air Quality Study
GV	gas venting
H_2S	hydrogen sulfide
HC	hydrocarbons
hp	horsepower
LTO	landing/takeoff
MMS	Minerals Management Service
MOAD	MMS Offshore Activities Database
MUD	mud degreasing
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NTL	Notice to Lessees
OCS	Outer Continental Shelf
ODS	Offshore Data Services
OOC	Offshore Operators Committee

LIST OF ABBREVIATIONS (Continued)

PM	particulate matter
PM_{10}	particulate matter less than 10 microns
$PM_{2.5}$	particulate matter less than 2.5 microns
PSD	prevention of significant deterioration
QA	quality assurance
QC	quality control
SO_x	oxides of sulfur
SO_2	sulfur dioxide
STI	Sonoma Technology, Inc.
STO	storage tanks
THC	total hydrocarbons
TSP	total suspended particulates
USCG	U.S. Coast Guard
VOC	volatile organic compounds

1. INTRODUCTION

This document is the final report for the Minerals Management Service (MMS) project "Emission Inventories of OCS Production and Development Activities in the Gulf of Mexico" (MMS Contract No. J-30856). This document provides an overview of the technical work performed and the results of the current and historical emission inventories developed in this study.

1.1 BACKGROUND

The region east of the Mississippi Delta contains the Breton National Wildlife Area (BNWA), protected under the Clean Air Act as a Class I air quality area. Air pollutant emissions from sources within 100 km of all Class I areas are regulated to prevent significant deterioration of air quality (through the prevention of significant deterioration [PSD] permitting process). For regulatory purposes, significant air quality deterioration is defined as an increase in an air pollutant's concentration (determined through air quality modeling) that exceeds an increment defined for each pollutant (sulfur dioxide [SO_2], nitrogen dioxide [NO_2], etc.) and averaging period.

A large number of oil and gas producing platforms, numerous onshore industrial sources, and several urbanized areas are located within 100 km of the BNWA (see **Figure 1-1**). Concern is mounting that the SO_2 and NO_2 PSD increments for the BNWA have nearly been consumed due to emissions from these sources.

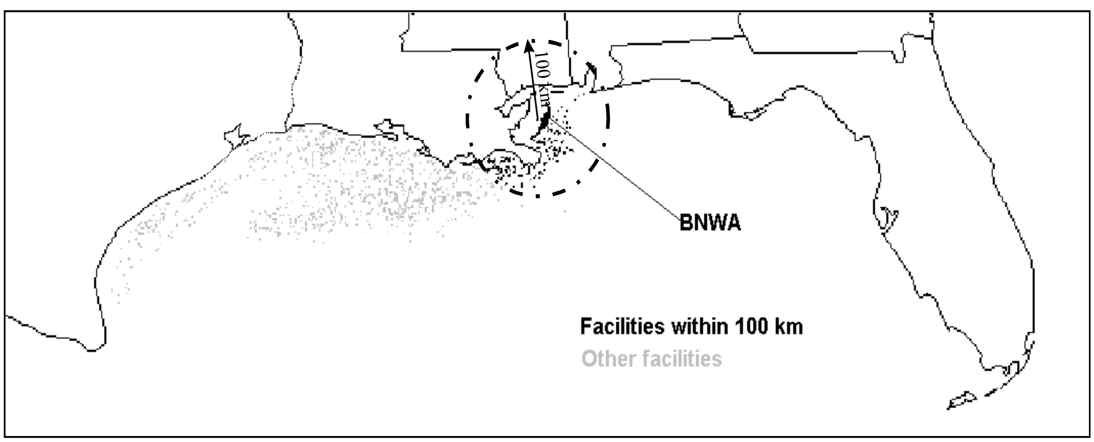


Figure 1-1. Outer continental shelf (OCS) facilities in the Gulf of Mexico.

The determination of the BNWA's PSD status depends on regional air quality modeling. In turn, modeling results depend on the qualities of the model algorithms, meteorological input data, and emissions input data. In order to improve the quality of the inputs, the MMS issued a Notice to Lessees (NTL No. 96-04, dated August 15, 1996) that required outer continental shelf

(OCS) leaseholders within 100 km of BNWA to collect and submit meteorological, air quality, and emissions data. In response, the Offshore Operators Committee (OOC) initiated the Breton Aerometric Monitoring Program (BAMP) to collect air quality, meteorological, and emissions information. This report summarizes the results of emissions data collection efforts that took place during the year 2000. Approximately 500 offshore structures within 100 km of the BNWA are represented.

1.2 PROJECT OBJECTIVES

The purpose of this project, "Emission Inventories of OCS Production and Development Activities in the Gulf of Mexico" (MMS Contract No. J-30856) is to provide technical support for the development of the year-2000 BAMP and past years' (1977, 1988) gridded emission inventories. The gridded OCS emission inventories include primary air pollutants (carbon monoxide [CO], oxides of nitrogen [NO_x], sulfur oxides [SO_x], total suspended particulates [TSP], particulate matter less than 10 microns [PM_{10}], particulate matter less than 2.5 microns [$PM_{2.5}$], total hydrocarbons [THC], and volatile organic compounds [VOC]). These inventories include area and mobile sources that are spatially resolved to the grid-cell level, and point sources that are assigned to specific coordinates. Past-year inventories were developed from a 1991 base-year inventory. Additionally, software tools to assist the MMS to collect and manage the OCS emission inventory in the future were developed.

1.3 SCOPE OF WORK

1.3.1 Prepare Backcast Inventories for 1977 and 1988

Historical inventories for the entire Gulf of Mexico were prepared for 1977 and 1988 to support PSD baseline analyses. OCS emission source categories included in the historical inventories are shown in **Table 1-1**. The quality of the historical inventories depends heavily on the reliability of the source data. For this project, the sources of data were (a) the year-2000 emission inventory developed during the BAMP, (b) the 1993 gulf-wide emission inventory developed by MMS, and (c) historical records of oil and gas exploration and production in the Gulf of Mexico.

Table 1-1. OCS emission inventory source categories.

Source Category	Source Description
Platform Sources	Platform Equipment -engines and turbines -storage tanks -flares -glycol regenerators -vents -amine units -fugitive emissions -petroleum loading/unloading
Platform-Associated Sources	Crew/Supply Boats Oil Barges Shuttle Tankers Tugboats Research Vessels Crew Helicopters Construction Barges
Pipeline Sources	Pipeline Construction Equipment -pipeline barges -tugboats
Exploration & Drilling	Drilling Equipment -Engines and Turbines -Mud Degassing

1.3.2 Compile a Current-year BAMP Inventory of Platform Sources

An inventory of offshore facilities (including platforms and wellheads) for the BAMP study period was constructed. The inventory was based on MMS' survey of facilities within 100 km of the BNWA (per NTL 96-04). The inventory covered platform equipment and processes for surveyed facilities. Many significant emissions sources within the OCS are non-platform or temporary sources that were not surveyed, such as crew and supply boats, crew and supply helicopters, pipeline-laying vessels, exploratory and drilling vessels, military and commercial ships, barges, commercial fishing boats, recreational boats, geogenic sources, and biogenic sources. (However, the historical 1977 and 1988 inventories, discussed above, included non-platform area sources for the gulf-wide area.) Current year (BAMP-period) estimates of OCS platform emission sources were prepared for the following platform source categories:

- Platform equipment
- Flares
- Glycol regenerators
- Vents
- Amine units
- Petroleum loading and unloading operations
- Engines and turbines
- Storage tanks
- Platform drilling equipment
- Boilers
- Fugitive emissions

MMS' survey data included an MMS-approved source identification code, owner, location, source type code, and activation/de-activation (or "deployment") dates for each platform. In addition, the data include month- and source-specific activity data, such as times of operation, process throughputs, and control efficiencies. The database is organized according to individual sources, structure, complexes, and lessees at monthly averaging periods (or more highly resolved time periods for selected upset conditions).

Specialized data collection software was developed (Breton Offshore Activities Data System for Air Quality [BOADS]) for use by MMS to collect and perform end-user QA/QC of the current-year emissions activity data. The BOADS software incorporated automated QA/QC including checks of (1) parameter ranges and magnitudes by source categories and (2) data formats and units to ensure data integrity.

1.3.3 Develop a Database Management System (DBMS)

The final element of the study was to provide a reliable and efficient means to produce and maintain the OCS activity and emissions databases (including the current-year BNWA inventory). To accomplish this objective, a relational DBMS built in Oracle was developed and delivered to the MMS. The DBMS facilitates data input, rapid data access, automated data reports, and efficient data queries. The DBMS also computes and provides error warnings, range checks, and outlier flags.

1.4 GUIDE TO THIS REPORT

The remainder of this report is divided into sections covering each of the three major elements of the study as listed above. Section 2 provides a summary of the methods and results of the historical backcasts. Section 3 provides a description of the current year BNWA inventory and an overview of the Oracle DBMS built to store the emission inventory. Appendix A details emissions backcasting estimation methods and data sources. Appendices B and C contain graphical displays. Appendix D presents emission activity data storage formats. Appendix E presents current-year emissions estimation methods. Appendix F contains documentation of the DBMS.

2. PREPARE BACKCAST INVENTORIES FOR 1977 AND 1988

2.1 OVERVIEW OF HISTORICAL EMISSIONS

In this section, we provide an overall summary of the historical emissions for activities related to the development and production of oil and gas in the Gulf of Mexico estimated in this study and provide brief descriptions of the data sources and methods used to estimate historical emissions. More details of the inventory compilation are provided in Appendix A. The emissions-related activities covered in this emission inventory compilation are divided into stationary (e.g., platform-based equipment) and mobile (e.g., transitory equipment including crew and supply boats, drill and pipeline-laying vessels, etc.) sources.

Tables 2-1a and 2-1b list the emissions for each of the source categories included in this study for 1977 and 1988. As shown in the table, no single source category is responsible for most of the emissions. Overall, platform emissions are greater than mobile source emissions. Among platform sources, platform equipment (e.g., engines, turbines, and boilers) are the predominant source of combustion-related emissions, venting is the predominant source of THC and VOC, followed closely by glycol units. Among mobile sources, crew and supply boats are the single largest source category of all pollutants. It is also interesting to note that different pollutants trend differently from 1977 to 1988, with some increasing, some decreasing, and some remaining about the same.

Table 2-1a. Total 1977 emissions related to OCS oil and gas production and development.

1977 Annual Total Emissions (tons)								
	CO	NO_x	TSP	PM_{10}	$PM_{2.5}$	SO_x	THC	VOC
Mobile Sources								
Helicopters	8	27	4	2	1	4	1	1
Crew & Supply Boats	1,493	13,305	331	331	304	2,408	142	142
Exploration Ships	178	1,367	34	34	31	631	18	18
Drill Ships	320	4,034	100	100	92	1,811	25	25
Pipe Laying Ships	110	848	21	21	19	392	11	11
Total Mobile	**2,109**	**19,581**	**489**	**488**	**448**	**5,246**	**198**	**198**
Stationary Sources								
Construction	685	2,580	56	46	39	293	73	66
Drilling	3,521	13,257	289	237	198	1,674	373	328
Platform equipment	76,599	57,946	486	486	486	182	15,791	1,101
Flaring	2,755	506	7	7	7	4,807	0	0
Glycol units	0	0	0	0	0	0	12,530	12,430
Venting	0	0	0	0	0	0	434,895	24,319
Mud Degassing	0	0	0	0	0	0	2,998	0
Storage Tanks	0	0	0	0	0	0	9,843	9,138
Total Stationary	**83,561**	**74,289**	**838**	**777**	**730**	**6,956**	**476,502**	**47,382**
TOTAL	**85,670**	**93,869**	**1,328**	**1,265**	**1,179**	**12,202**	**476,699**	**47,580**

Table 2-1b. Total 1988 emissions related to OCS oil and gas production and development.

1988 Annual Total Emissions (tons)								
	CO	NO_x	TSP	PM_{10}	$PM_{2.5}$	SO_x	THC	VOC
Mobile Sources								
Helicopters	14	48	7	4	3	7	1	1
Crew & Supply Boats	2,668	23,773	591	591	544	4,303	254	254
Exploration Ships	178	1,367	34	34	31	631	18	18
Drill Ships	566	7,141	176	176	162	3,206	46	46
Pipe Laying Ships	134	1,031	26	26	24	476	14	14
Total Mobile	**3,560**	**33,359**	**834**	**831**	**764**	**8,623**	**333**	**333**
Stationary Sources								
Construction	880	3,314	104	85	71	377	93	85
Drilling	1,759	6,621	144	119	99	836	186	164
Platform equipment	96,888	73,294	584	584	584	182	19,974	1,393
Flaring	1,212	223	3	3	3	2,114	0	0
Glycol units	0	0	0	0	0	0	15,226	15,105
Venting	0	0	0	0	0	0	235,508	13,169
Mud Degassing	0	0	0	0	0	0	2,619	0
Storage Tanks	0	0	0	0	0	0	10,451	9,703
Total Stationary	**100,739**	**83,452**	**835**	**791**	**758**	**3,509**	**284,057**	**39,619**
TOTAL	**104,299**	**116,811**	**1,669**	**1,622**	**1,521**	**12,132**	**284,390**	**39,951**

Mobile source emissions were assigned spatial distributions and platform equipment emissions were assigned geographic coordinates as described later in this section (see **Figures 2-1 and 2-2**; see Appendix D for documentation and spatial data). Complete sets of figures for 1977 and 1988 are included in Appendix B for all mobile source emissions and in Appendix C for platform emissions.

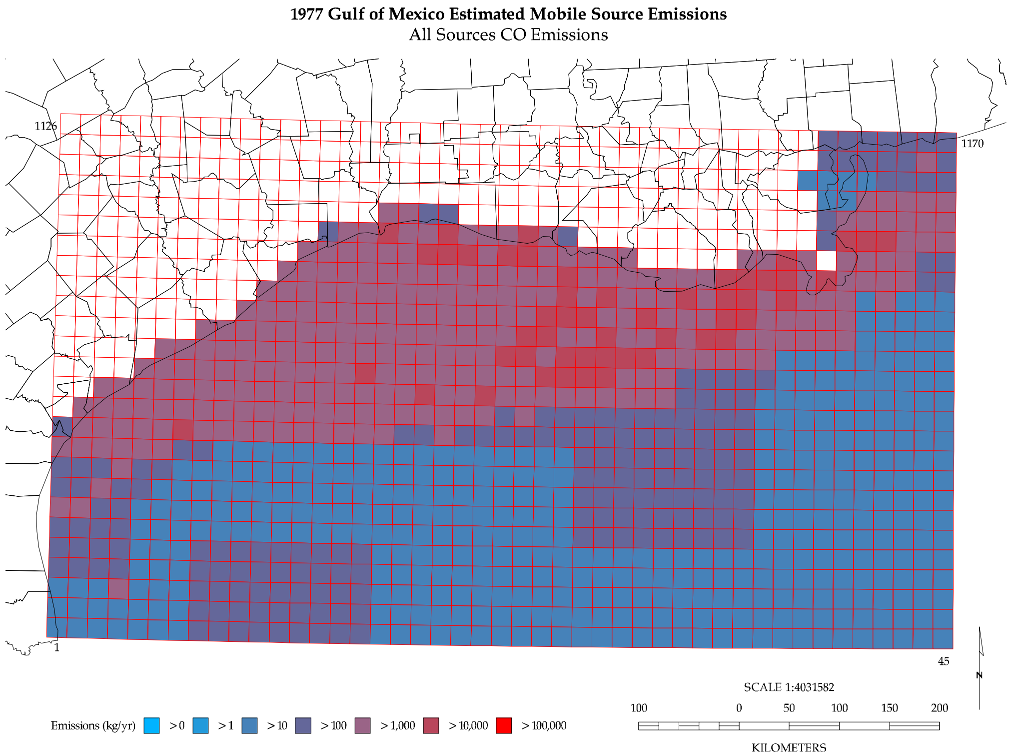


Figure 2-1. Example gridded mobile source emissions display.
(Projection is defined in Appendix B.)

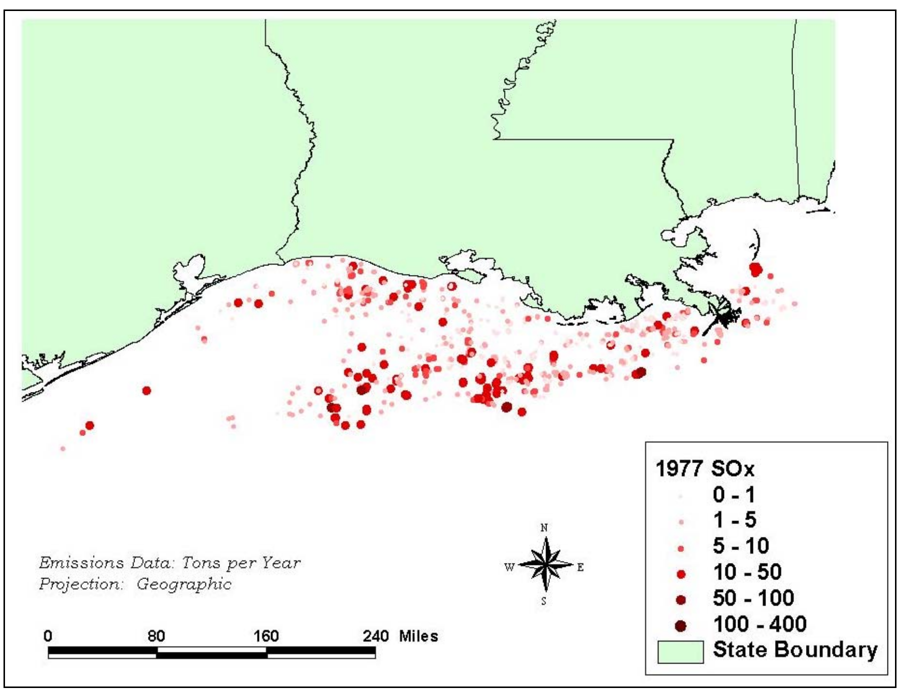


Figure 2-2. Example gulf-wide platform emissions display.
(Projection is defined in Appendix C.)

2.2 STATIONARY SOURCES

2.2.1 Summary of Technical Approach

The gulf-wide emissions inventory (MOADS 3), which was developed as part of the Gulf of Mexico Air Quality Study (GMAQS) in 1993, served as the basis for many of the backcasts performed in this study. Although MOADS 3 was the best available data for gulf-wide emissions estimates, it still required considerable augmentation and modification for use in backcasting the 1977 and 1988 historical emissions inventories. For example, not all platform-related sources required for this study were included in the 1993 MOADS 3 (see **Table 2-2).** Specifically, drilling and construction sources were added, and improved emission factors and activity data were incorporated.

The adjusted MOADS 3 inventory was then used as a baseline from which historical emissions could be estimated by using economic scaling factors or extrapolated activity data (such as commissioning or decommissioning dates, growth or decline in production rates, estimated activity variation of platform equipment, the addition of emissions controls, or the introduction of new technologies). For some sources, emissions modeling techniques were employed to directly estimate emissions from emission factors and average or default values. In other cases, a range of possible emissions estimates was generated to examine the relative importance of the emissions sources and the effects of selected estimation methodologies. Historical emissions were distributed in space and time according to historical activity data or more recently developed Gulf-specific information by using spatial analysis techniques. Detailed descriptions of data sources, emission factors, and estimation methods are provided in Appendix A.

Table 2-2. Basis and source of emissions or activity data for emission source categories.

Source Category	Source Description	Source Type	Emissions Data	Source of Emissions Data
Platform Sources	Platform Equipment -engines and turbines -storage tanks -flares -glycol regenerators -vents	Stationary	Physical and operational data for stationary source activity	Data from MMS BOADS survey program and/or existing emissions data; MOADS 3 emissions database
Platform Associated Sources	Construction Barges	Area	Construction activity	MMS platform construction and modification records
Exploration & Drilling	Drilling Equipment -Engines and Turbines -Mud Degassing	Area	Activity data	Drill rig permits and schedules from MMS database

2.2.2 Results

Figures 2-3 and 2-4 depict the relative emissions for each platform-related emissions source for 1977 and 1988 and the total emissions for all platform equipment combined. Platform equipment includes mud degassing (MUD), storage tanks (STO), gas venting (GV), glycol units (GLY), flares (FL), construction (CON), drilling (DRILL) and engines, turbines, and boilers (EQ).

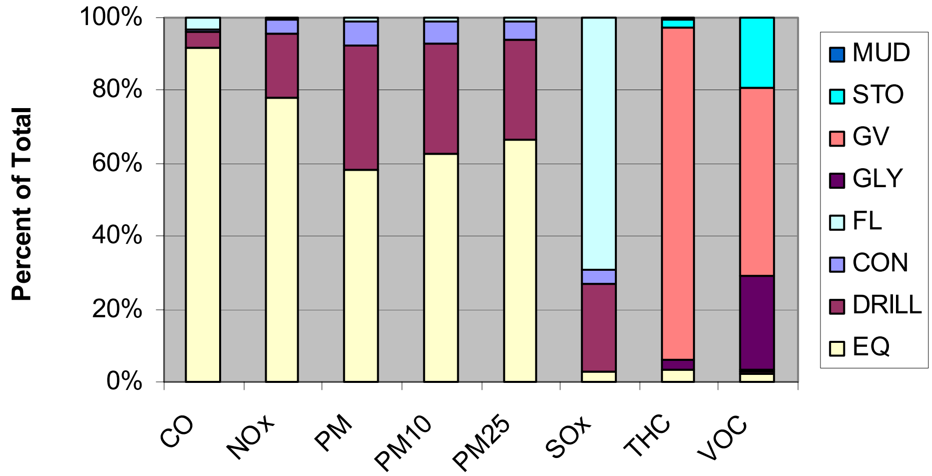


Figure 2-3a. Relative contribution by source type to 1977 emissions.

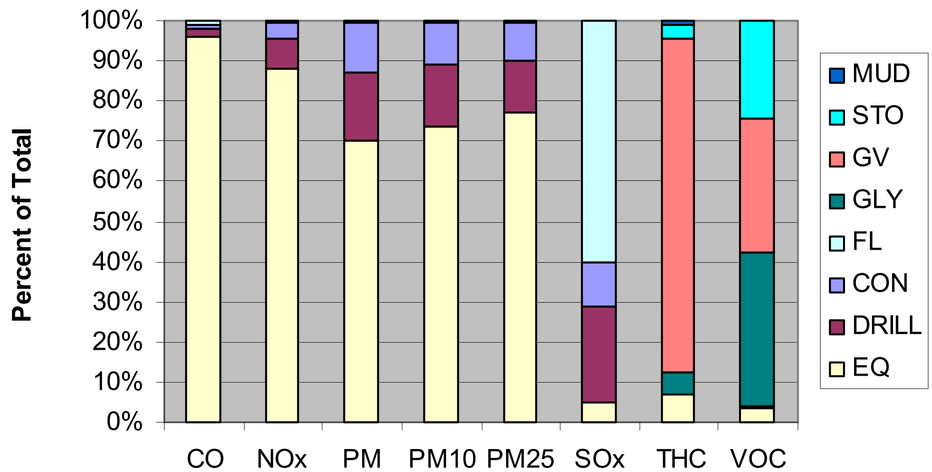


Figure 2-3b. Relative contribution by source type to 1988 emissions.

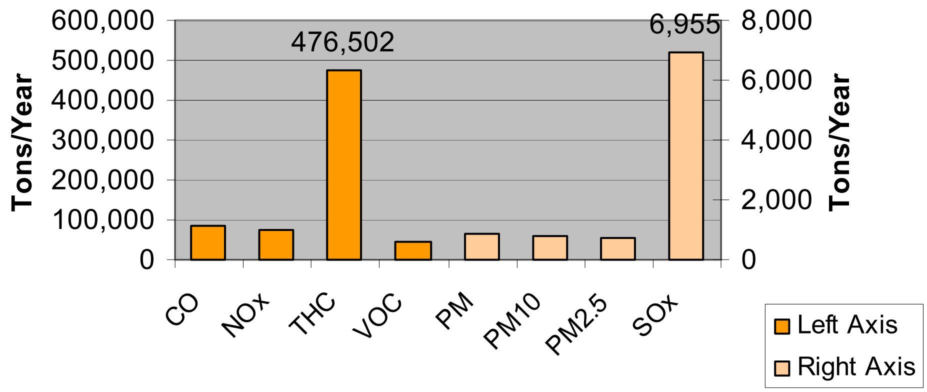


Figure 2-4a. Estimated gulf-wide emissions for 1977.

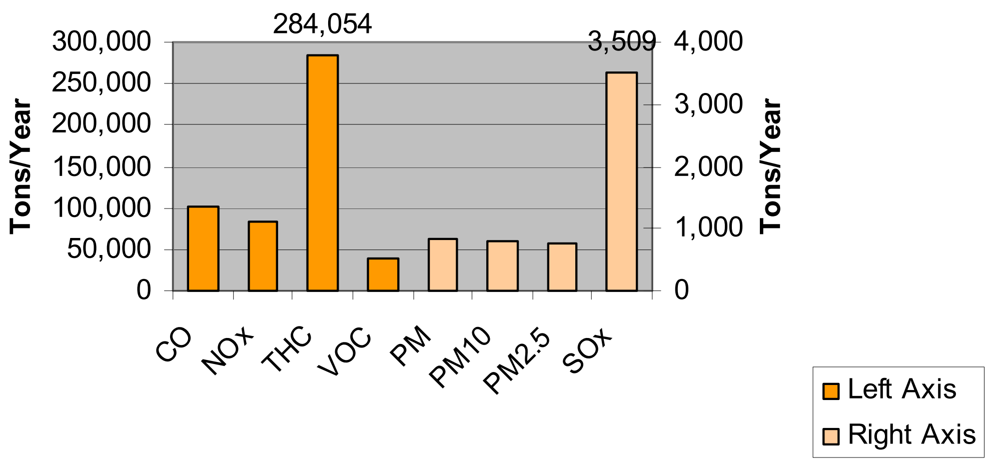


Figure 2-4b. Estimated gulf-wide emissions for 1988.

Discussion

Platform equipment (e.g., engines, boilers, and turbines) dominate the combustion-related emissions (e.g., NO_x, CO, and PM). Other notable sources of NO_x, CO, and PM are drilling and construction-related activities. SO_x emissions in 1977 and 1988 are primarily from flaring activity. Flaring-related SO_x emissions represent about 60 to 65% of the total SO_x inventory. Drilling is the next largest source of SO_x emissions and accounts for about 20% of the SO_x inventory. Other sources of SO_x, in descending order of importance, are construction emissions and platform equipment (primarily diesel combustion).

THC and VOC emissions have notably different source contributions than the combustion-related pollutants. THC is mainly the result of gas venting activities (about 80 to 90% of the THC inventory). However, since methane is the primary component of vented gas, VOC emissions are not as dominated by gas venting activities as are THC emissions. Gas venting accounts for only about 50% of VOC emissions. Other major contributors to VOC emissions are glycol units and storage tank losses.

Uncertainties

Since a small number of source categories can dominate certain pollutants, changes in industry practices for isolated categories can dramatically influence emissions. For example, the change in the amount of gas released as a function of production is decreasing over time (see **Figure 2-5**). A more comprehensive evaluation of the underlying data reveals that the amount of casinghead gas (e.g., gas from oil wells) released is decreasing substantially, while gas released from gas wells has increased over the past 20 years.

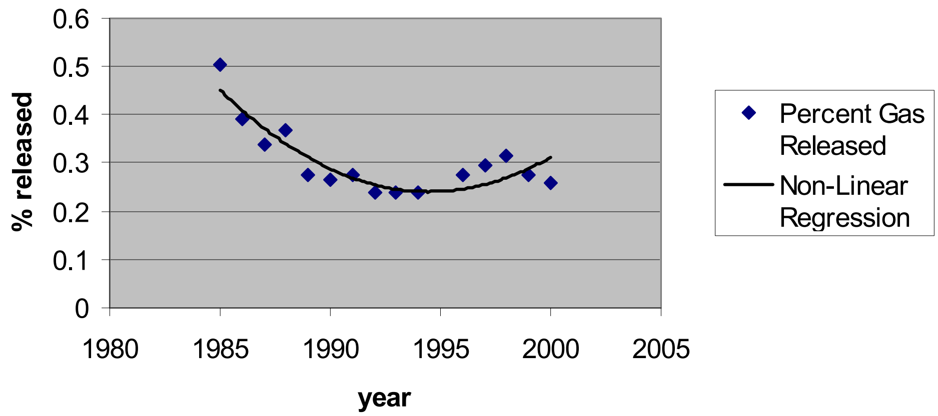


Figure 2-5. Natural gas released to vents or flares in the Gulf of Mexico.

SO_x and THC emissions estimates can vary considerably depending on the methodology used. The emissions estimates rely on the ratio of gas flared or vented to production rate. Depending on the assumed amount of flaring or venting in the Gulf of Mexico, SO_x and THC emissions estimates can vary by almost 20%.

Temporal Variations

Determination of precise temporal variation in historical activity levels was not possible for most source categories due to lack of detailed data. Typical industry average temporal profiles were assigned instead. There were more temporal data available for 1988 than for 1977; thus, 1988 data were used for both historical years. Temporal data were obtained for borehole drilling, mud degassing, platform construction, venting, and flaring activities. No temporal information was available for platform equipment, glycol units, and storage tank emissions; thus, they were assigned a flat temporal profile (i.e., no monthly variation). The estimated monthly activity levels for those equipment types that did vary are depicted in **Figure 2-6**.

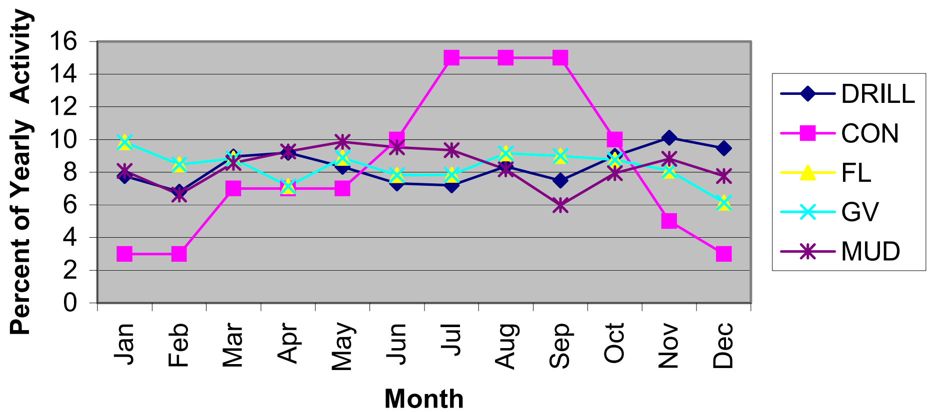


Figure 2-6. The temporal variation of activity by equipment type in 1988.

Construction activity was assigned the greatest variability with a peak of about 15% of the annual activity occurring during a summer month and less than 5% of annual activity occurring during a winter month. Flaring and venting also showed some variability ranging from a low of about 5% of annual activity to about 10% of annual activity on a monthly basis. Other source types (e.g., drilling and mud degassing) had profiles that only varied by a small percent throughout the year. As a result, most pollutants generally do not have large month-to-month variability, except for SO_x and THC emissions, which are more heavily influenced by the contribution from equipment emissions used during drilling and construction and by flaring and venting patterns. **Figure 2-7** depicts the variation of monthly emissions in 1988 for each pollutant for all source types combined.

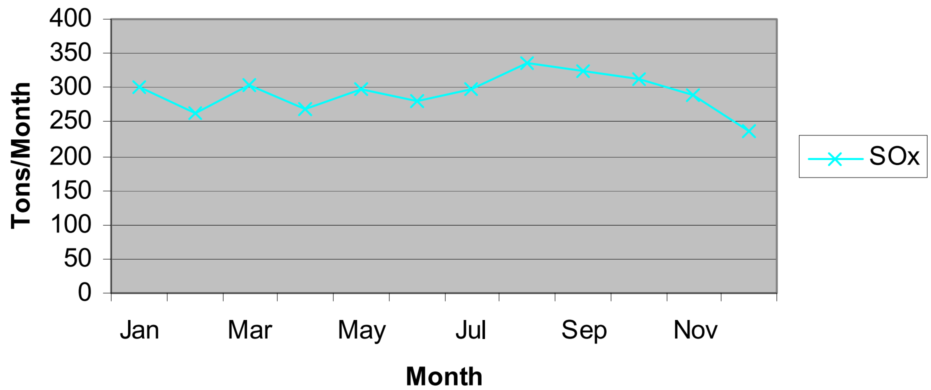


Figure 2-7a. Monthly variation of SO_x emissions in 1988.

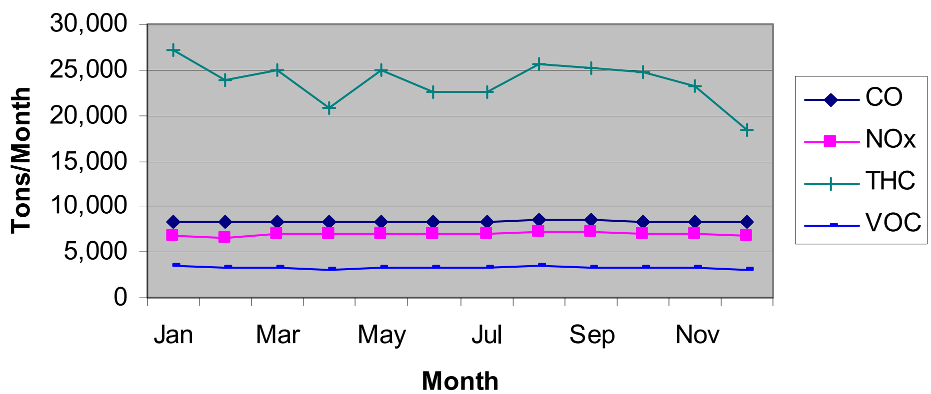


Figure 2-7b. Monthly variation of CO, NO_x, THC, and VOC emissions in 1988.

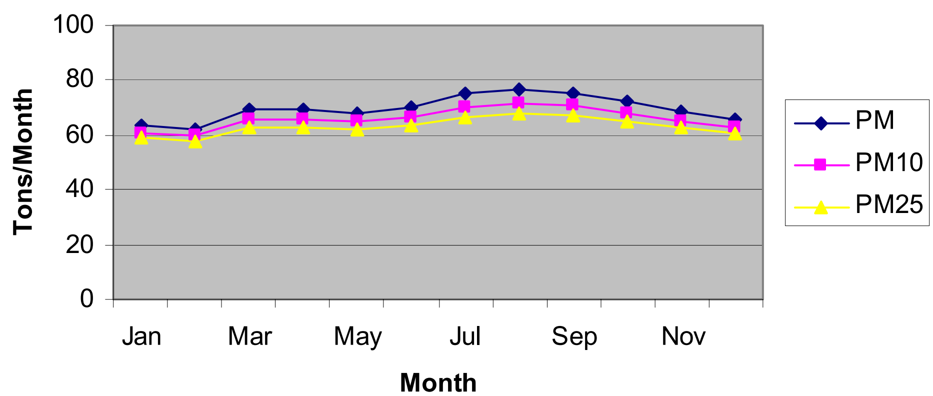


Figure 2-7c. Monthly variation of PM emissions in 1988.

Historical Trends

Oil and gas development and production are subject to economic cycles and technological limitations. Examination of the historical activity data compiled in this study reveals several observable trends. For example, within 100 km of the BNWA the number of platforms approximately doubled, increasing from 300 to 500, from 1990 to 2000. It is also interesting to note that the average platform depth was relatively unchanged at approximately 100 feet during the period from 1977 to 1990, but the average depth more than doubled after 1998 through the current year. The deeper the water, the more energy is required to construct the platform, which is directly proportional to emissions generation. This same trend is inherent in drilling activity data as well. Although the actual numbers of wells drilled per year is decreasing due to better detection equipment and past exploration, the depth of wells drilled is increasing over time.

Interestingly, from 1977 to 1990, the amount of gas released to vent or flare equipment declined; but the amount released after 1990 increased in concert with increasing production levels (note that gulf-wide oil production has almost doubled since 1990). Emissions from diesel engines also reflect a doubling of diesel engine use from 1990 to 2000. A reduction in flaring activity from 1977 to 1990 was also observed. As the amount of flaring decreases, the emissions from other platform equipment contribute a greater share of the inventory.

2.3 MOBILE SOURCES

This section summarizes the approach and results of the development of gridded emissions inventories for mobile sources operating in the OCS areas of the Gulf of Mexico. The subjects of this study were only those mobile sources related to oil and gas exploration and production activities in the OCS and included

- crew and supply boats,
- pipeline-laying ships,
- research and exploration vessels,
- crew and supply helicopters, and
- drilling ships.

The data sources and methods for estimating emissions from the each source category were somewhat different; the methodologies and results are discussed in the following subsections. Some issues are also common to more than one category. Gulf-wide emissions were spatially allocated to a 45 (west to east) by 26 (south to north) grid, about 20-km by 20-km with a grid origin (southwest corner) located at coordinates 26 degrees North latitude and 97.2 degrees East longitude. All gridding was performed using ESRI's ARC/INFO, a commonly used GIS software package. (Map projection is provided in Appendix B.)

The 1993 MMS Offshore Activity Data Bases (MOADS) served as the starting point for many of the backcasts. MOADS contains data pertaining to the numbers, activities, fuel consumption, and engine sizes of crew and supply boats and helicopters. These data provide 1993 emissions totals, which serve as basis for backcasting and gridding of emissions for some source categories. In addition, MMS recently published a series of data compact discs (CD) entitled "50 Year Anniversary Offshore Oil and Gas CD Collection." Data from this four-CD set and additional data downloaded from the MMS Internet web site were used to estimate the numbers of active platforms, production levels, and drilling and pipeline-laying activities and locations in 1977 and 1988. Ship vessel registration and characteristics data maintained by the U.S. Coast Guard (USCG) were accessed and used to characterize the size and propulsion units of research vessels. A private data source (Offshore Data Services [ODS], 1977 and 1988) provided historical information about pipeline-laying and drill-ship activities. For each mobile source category, specific emission factors were obtained from EPA databases (AP42 and/or NONROAD) for THC, CO, NO_x, SO_x, and TSP. VOC factors were expressed as fractions of THC emissions, and PM_{10} and $PM_{2.5}$ factors were expressed as fractions of TSP emissions.

Crew and Supply Helicopters

There are 13 companies operating helicopters in the OCS region, which are represented in the 1993 MOADS, from which 1993 helicopter activity levels and areas of operations, as well as emissions estimates, were derived. Helicopter emission factors are from AP-42, Table II-1-8. We selected emissions factors representative of turbine engines in the helicopter fleet operating in the Gulf of Mexico OCS region and assumed a jet fuel density factor of 2.6 kg/gal. Emissions were estimated for all phases of helicopter operation since these helicopters most often operate within the convective marine mixing layer. Since landings/takeoffs (LTOs) comprise a very small portion of the total hours of operation and no LTO data were available, they are ignored in this analysis. Furthermore, since helicopters utilize a relatively constant amount of power for all phases of operation, a single emission factor was used for all flight modes. Thus, emissions were estimated as the product of the emission factor and the total hours of flight.

Helicopter emissions for 1988 and 1977 were estimated by assuming that OCS-wide emissions were proportional to the number of platforms operating in those years compared to 1993. The total OCS emissions were then spatially allocated by assuming that emissions in each cell were proportional to the number of operating platforms in that cell. $PM_{2.5}$ and PM_{10} were estimated from TSP by applying mass fractions of 0.390 and 0.553 taken from the NONROAD SPECIATE database version 1.5 (profile #34001 - Jet Aircraft). VOC was estimated as 90% of THC. Based upon the SPECIATE database (Version 3.0, profile 1098 - Aircraft Landing/Takeoff [LTO] - Commercial), it was assumed that methane and ethane comprise about 10% of THC.

The 1993 MOADS database contained estimates only of crew and supply helicopters' fuel consumption and operating hours by helicopter type. No information was available for routes flown or departure/destination pair statistics. Also, spatial allocation factors and information were not preserved in the MOADS database. Thus, it was required that we devise a new spatial allocation procedure for this historical backcasting effort.

It was determined in the 1993 GMAQS study that helicopter routing is frequently indirect, offshore trips often involve stops at more than one platform and may involve multiple refueling stops at certain offshore platforms. We observed that the spatial distribution of the final gridded offshore area source emission inventories plotted in the GMAQS report largely reflected the distribution of platforms. Thus, our spatial allocation procedures simply allocated total offshore helicopter emissions in proportion to the number of platforms in each grid cell.

Total offshore emissions were calculated as the product of the total flight hours for each helicopter type and an emissions factor appropriate to the specific engine on each helicopter type. The distance traveled by the helicopter is implicitly accounted for in the number of flight hours as distance traveled is simply the product of flight hours and average speed. The specific routes of flights were not explicitly treated; it was assumed that the level of helicopter activities and routing are related to the position and number of offshore platforms. It can be argued that this method might, in principle, lead to underestimation of emissions closer to shore since all offshore crew and supply helicopters initially embark from land bases. However, allocation of emissions to near-shore platforms included emissions due to multiple stops and refueled missions that actually occurred further offshore. Thus, the possible short-changing of emissions from helicopters transiting the near-shore tracts en route to tracts farther offshore is at least qualitatively offset by this allocation to near-shore tracts of emissions from extra offshore legs.

As a practical matter, an elaborate spatial allocation scheme that explicitly accounts for the large number of possible helicopter routes is not warranted given the overall level of uncertainty involved in the emissions backcasting process. The spatial distribution produced by our methods is reasonably plausible and consistent with the final inventories presented in the GMAQS report.

Crew and Supply Boats

The MOADS data contains 1993 annual usage data in hours and rated horsepower for the crew and supply boats by engine type. The crew and supply boat emission factors were derived from information given in Table 5-1 of *Analysis of Commercial Marine Vessels Emissions and Fuel Consumption Data* (U.S. Environmental Protection Agency, 2000). This reference presents the following equation for calculating PM, NO_x, CO, and HC emissions factors:

Emissions Rate (g/kW-hr) = a (Fractional Load)^(-x) + b **(2-1)**

The equation for SO_2 is

Emissions Rate (g/kW-hr) = a (Fuel Sulfur Flow in g/kW-hr) + b **(2-2)**

The equation for fuel consumption is

Fuel Consumption (g/kW-hr) = 14.12/(Fractional Load) + 205.717 **(2-3)**

Marine diesel fuel sulfur level was obtained from Table 4 of In-Use Marine Diesel Fuel (U.S. Environmental Protection Agency, 1999) as 0.36% by weight for DMA, the predominant marine fuel for medium and small engine vessels. Emission factors were estimated at 70% load, based on Table 5-2 in the reference above, and expressed as mass per horsepower-hour (hp-hr).

The 1977 and 1988 total emissions were estimated by scaling the 1993 emissions by the ratio of platforms operating in 1977 and 1988 to those operating in 1993, respectively. The total emissions were increased by a factor of 1.56 to account for the fact that only 64% of the crew and supply boat operators responded to the 1993 MOADS activity survey. The spatial allocation procedures used were the same as for crew and supply helicopters, with each cell receiving the amount of emissions proportional to the number of platforms present.

PM_{10} and $PM_{2.5}$ were estimated from TSP using the fractions 1.0 and 0.92 which were obtained from the NONROAD SPECIATE database version 1.5 profile # 32202 - Heavy duty diesel.

For lack of specific data, it was assumed that VOC emissions are approximately equal to THC. This seems reasonable in the case of heavy-duty diesel engines since they emit little methane or ethane.

The method used to estimate 1993 crew and supply boat emissions was similar to that used in the 1993 MOADS, but we used updated emission factors. 1993 annual boat usage data were obtained from the MOADS database. Emission factors were calculated on the basis of a recent EPA report (U.S. Environmental Protection Agency, 2000). The EPA emission factor equations were derived from a substantially larger database than previous factors, cover a wide range of engine sizes (encompassing the boat types of interest here), and are reported to be an improvement over previous emission factor estimation methods.

Table 2-3. Marine engine emission factor and fuel consumption algorithms, in g/kW-hr, for all marine engines (U.S. Environmental Protection Agency, 2000).

Pollutant	Exponent (x)	Intercept (b)	Coefficient (a)
PM	1.5	0.2551	0.0059
NO_x	1.5	10.4496	0.1255
NO_2	1.5	15.5247	0.18865
SO_2	n/a	n/x	2.3735
CO	1	n/s	0.8378
HC	1.5	n/s	0.0667
CO_2	1	648.6	44.1

1. All regressions but SO_2 are in the form of
   Emissions Rate (g/kW-hr) = a (Fractional Load) -x + b
2. Fractional load is equal to actual engine output divided by rated engine output.
3. The SO_2 regression is the form of:
   Emissions Rate (g/kW-hr) = a (Fuel Sulfur Flow in g/kW-hr) + b
4. Fuel Consumption (g/kW-hr) = 14.12/(Fractional Load) + 205.717. To convert the calculated fuel consumption into units of (gallons pounds per kW-hr), divide by these figures by 3780 g/gallon.
5. n/a = not applicable; n/s = not statistically significant.

Due to the use of updated emissions factors in this study, total 1993 emissions estimated in this study for crew and supply boats were somewhat different than the totals reported in the 1993 GMAQS report. The current estimates of crew and supply boats NO_x emissions are significantly higher, VOC significantly lower, and CO about the same as reported in the

GMAQS report. In this study, we opted to use the most current emissions factors rather than replicating the 1993 MOADS results.

As was the case for crew and supply helicopters, spatial allocation factors and information were not preserved in the 1993 MOADS database. Thus, it was required that we devise a new spatial allocation procedure for this historical backcasting effort.

Crew and supply boat emissions were calculated as the product of the total operating hours, engine output, and the EPA emission factor discussed above. In this case, operating hours are a better measure of emissions than distance traveled since boats often operate at high load factors even when they are not underway in the cruise mode.

Just as for helicopters, it was determined in the 1993 GMAQS study that boat routing is frequently indirect, and offshore trips often involve stops at more than one platform. Also, significant portions of boat operating hours were spent maneuvering or “station-keeping” at the platform sites. Again, we observed that the spatial distribution of the final gridded offshore area source emission inventories plotted in the GMAQS report largely reflected the distribution of platforms. Thus, our spatial allocation procedures simply allocated total offshore emissions in proportion to the number of platforms in each grid cell. It can be argued that this method might, in principle, lead to underestimation of crew and supply boat emissions closer to shore because these boats initially embark from onshore ports. However, allocations of emissions to near-shore platforms included emissions due to multiple stops and onsite maneuvering that actually occurred further offshore. Thus, the possible short-changing of emissions from boats transiting the near-shore tracts en route to tracts farther offshore is at least qualitatively offset by this allocation of emissions to near-shore from extra offshore legs and non-cruise-related operating activity.

At this time, a complicated method to account for the large number of possible routes is not justified given the current level of uncertainty with the process of emissions backcasting. The spatial distribution produced by our methods is reasonably plausible and is consistent with the final inventories presented in the GMAQS report.

Drill Ships

Borehole data were obtained from the MMS web site (Minerals Management Service, 2000). These data sources contain detailed information about the locations and time of installation of exploratory boreholes for both 1977 and 1988. To determine the duration of the drilling for each borehole, the “spud date” was assumed to indicate the start of drilling, and the “total depth date”, the final day. Continuous operation was assumed between these two dates. The effective drill period was assumed to be the duration between the spud and total depth dates or 10 days, whichever was longer. Only drilling that occurred within the calendar year for each year was considered (i.e., if drilling lasted from December 1988 to January 1989, only December was counted).

Drill ship emission factors were obtained from Table 5-1 of Analysis of Commercial Marine Vessels Emissions and Fuel Consumption Data (U.S. Environmental Protection Agency, 2000). The equation published therein for calculating PM, NO_x, CO, and HC emissions factors is

$$\text{Emissions Rate (g/kW-hr)} = a\ (\text{Fractional Load})^{(-x)} + b \qquad \textbf{(2-4)}$$

The equation for SO_2 is

$$\text{Emissions Rate (g/kW-hr)} = a\ (\text{Fuel Sulfur Flow in g/kW-hr}) + b \qquad \textbf{(2-5)}$$

The equation given for fuel consumption is

$$\text{Fuel Consumption (g/kW-hr)} = 14.12/(\text{Fractional Load}) + 205.717 \qquad \textbf{(2-6)}$$

However, since we did not have fractional load data, we used an average drill ship fuel usage rate of 2256 gallons/day, which was published in an April 1995 letter from the Offshore Operators Committee to Chris Oynes of MMS. Marine diesel fuel sulfur levels were obtained from Table 4 of In-Use Marine Diesel Fuel (U.S. Environmental Protection Agency, 1999) as 0.91 % by weight for DMB (the predominant marine fuel for large engine vessels). Emission factors measured in terms of the mass of emissions per mass of fuel consumed were converted to units of kg emissions/gal fuel by using a fuel density of 3.0 kg/gal. Emission factors were estimated at 100% load.

Emissions were calculated for each drill ship voyage reported in the MMS borehole database for 1977 and 1988. Borehole coordinates were used to allocate emissions to the appropriate grid cell. Since only a small fraction of the vessel time is spent in transit and most borehole locations in these years were near the coastline, we allocated all emissions to the cells containing the borehole (i.e., we did not account for emissions associated with travel to and from the borehole locations).

Exploration Vessels

The activities of exploration vessels were estimated using 1988 MMS exploration and research permit data. Permit data for 1977 were not available, so we assumed the levels and locations of exploration vessel activities in 1977 to be the same as 1988. The MMS data were arranged by individual ship voyage with a specified time frame and area of exploration. We obtained USCG vessel registration data and vessel specifications for the vessel lists in the MMS permit archives. If the rated horsepower of a ship's engines were not available in this USCG database, horsepower was estimated using a correlation between boat length and horsepower developed from the available data points. If boat length was also unavailable, an average value of 3000hp was assumed.

The MMS permit data specified the lease block(s) in which a specific research/ exploration vessel was to operate. We assigned emissions from each voyage uniformly to all grid cells contained within the listed lease block(s). The records that did not have a block assigned or that had inconsistent data were examined and treated on a case-by-case basis. For example, in the case of voyages that involved a single ship without an assigned block, emissions were spread over the entire OCS. When a voyage date for a specific ship overlapped significantly with that of a second voyage of the same ship, the second record was ignored to avoid double-counting. It was also necessary to correct obvious inconsistencies or errors in the ship registry numbers. The number of operating days were estimated and allocated based on permit dates and blocks. Although in some cases the 1988 permits allowed exploration into 1989, the numbers of operating days were estimated using December 31, 1988, as a cutoff. It was determined through discussions with operators that the permit periods are often much longer than the actual voyages. Based on these discussions, the number of operating days per permit was assumed to be two weeks or the total permit period, whichever was smaller.

Exploration vessel emission factors were calculated in the same manner as for crew and supply boats. However, the load factor was estimated to be 60% (based on discussions with operators), and SO_2 emissions were estimated by assuming 0.91% fuel sulfur content, which is the average for marine diesel B (DMB), the most common distillate fuel for large-engine ocean-going vessels according to In-Use Marine Diesel Fuel (U.S. Environmental Protection Agency, 1999). Horsepower ratings were determined by matching either the ship's name or registry number to the available USCG vessel information data. Registry number was used first and if that did not produce a match, then the name was used. If these two did not produce a match, the average of 3000 hp was used—a situation that occurred for only four voyage permit records.

PM_{10} and $PM_{2.5}$ were estimated from TSP using the fractions 1.0 and 0.92, which were obtained from the EPA NONROAD SPECIATE database version 1.5 profile # 32202 – Heavy-duty diesel. Due to lack of data, it was assumed that VOC emissions are approximately equal to THC. This seems reasonable because heavy-duty diesel engines emit little methane or ethane.

Estimated exploration vessel emissions for each voyage were uniformly allocated to those grid cells within the lease tracts listed in each permit. If there were multiple tracts in any single permit record, each tract was assumed to have received an equal portion of the emissions, without regard to the size of the tract. Permit records that covered the entire Gulf had their associated emissions spread evenly across the entire OCS grid.

Pipe-Laying Ships

Information about pipelines installed in the Gulf of Mexico in 1977 and 1988 were obtained from the ODS. These data included information about the area (tract) into which the pipe was installed, pipe diameter, and pipeline length. In 1988, a few of the pipelines started and terminated in different tracts. These cases were examined individually. If the dominant length of the pipeline extended in one tract, that tract was assigned the whole length of the pipe. If the distance in each tract was roughly equal, the pipe length was divided between the tracts.

The ODS database also included some information on "days-to-complete", which was assumed to be equal to the duration of pipeline-laying activities in each case. However, this information was missing from many records. Using data from complete records, two statistical regression analyses were performed: one relating pipe length to installation duration, and the second relating both pipe length and diameter to installation duration. Although the regression using both pipe length and diameter resulted in fewer complete records, it produced a stronger regression coefficient and was therefore used to estimate the durations of pipe installations with missing completion time records. All pipeline installations were assumed to have been performed using ships with 3000 hp engines at 60% load. The emission factors for pipeline-laying ships were derived in the same manner as for exploration vessels, using 0.91% sulfur content. The emissions for each installation were calculated using a kg/hp-hr emission factor and the assumed hp and duration.

PM_{10} and $PM_{2.5}$ were estimated from TSP using the fractions 1.0 and 0.92, which were taken from the EPA NONROAD SPECIATE database version 1.5 profile # 32202 - Heavy duty diesel. Due to lack of data, it was assumed that VOC emissions are approximately equal to THC. This seems reasonable because heavy-duty diesel engines emit little methane or ethane.

Spatial allocation of estimated emissions from pipeline-laying ships began by totaling the emissions in each tract. Then, we assumed that pipelines generally extend from one facility or platform to another. Thus, the emissions total for each tract was allocated to each grid cell in proportion to the number of active platforms in the cell.

3. YEAR-2000 EMISSION INVENTORY FOR OUTER CONTINENTAL SHELF PLATFORMS IN THE VICINITY OF BRETON NATIONAL WILDLIFE AREA

3.1 INVENTORY DEVELOPMENT METHODS

3.1.1 Data Collection

The MMS directed OCS facility operators to report emissions activity data on a monthly basis throughout the year 2000 for facilities within 100 km of the BNWA. OCS facility operators responded by submitting electronic activity data files for approximately 510 facilities each month. The data files were used to calculate air emissions from equipment and processes that are common to oil and gas exploration and production facilities, including amine gas sweetening units, boilers, internal combustion engines, turbines, drilling operations, fugitives, flares, loading operations, glycol gas dehydrators, storage tanks, and vents.

Operators generated electronic data reports by applying BOADS. BOADS produces data files in Microsoft Access format. Each data file contained a single month's activity data (e.g., quantities of fuel consumed, process throughputs, etc.) for multiple facilities and multiple equipment or process units. The BOADS system is documented elsewhere (Coe et al., 2000). The MMS gathered the data files, resolved initial questions with the operators, and transmitted the data files to Sonoma Technology, Inc. (STI).

3.1.2 Input Data Processing, Quality Assurance, and Quality Control

For ease of use and convenience, STI processed and merged the entire set of BOADS data files into a single file with the same format characteristics as the original BOADS files. STI performed a manual QA/QC review of the merged data file and entered justifiable adjustments where warranted. As they were entered, QA/QC adjustments to the raw data were recorded and documented in a data table. This QA/QC record was included with the final version of the merged input database.

3.1.3 Database Management System Processes

Input data were loaded into an Oracle-based DBMS that was designed specifically to input, store, and process BOADS data files. Upon data load, the DBMS runs automated procedures to calculate and store emissions data and to record potential QC issues. The DBMS calculation procedures are described in Appendix E. The DBMS replicates BOADS QC checks, and also runs additional QC checks, which are also described in Appendix E. As part of its automated QC process, the DBMS generates a collection of QC reports in the form of ASCII files. The final version of the DBMS, loaded with BOADS input data, emissions results, and QC records was provided to the MMS with this report. Documentation for the DBMS is provided in Appendix F.

3.2 SUMMARY OF ESTIMATED EMISSIONS

Total emissions were summarized for all facilities that were reported to be "active" with at least one active equipment unit or process. Emissions were calculated for two scenarios: with existing control technologies installed and with no control technologies. The two scenarios differed very little. Controlled and uncontrolled emissions of NO_x, CO, and PM_{10} differed by 1% or less. Controlled and uncontrolled emissions of THC and VOC differed by 11% and 14%, respectively. With control technologies considered, SO_x emissions increased by 9% because Claus sulfur recovery units and equipment tail gas flares were considered to be control technologies for hydrogen sulfide (H_2S), which produce SO_x emissions as a by-product of H_2S combustion or conversion. The remainder of this section describes the controlled emissions scenario.

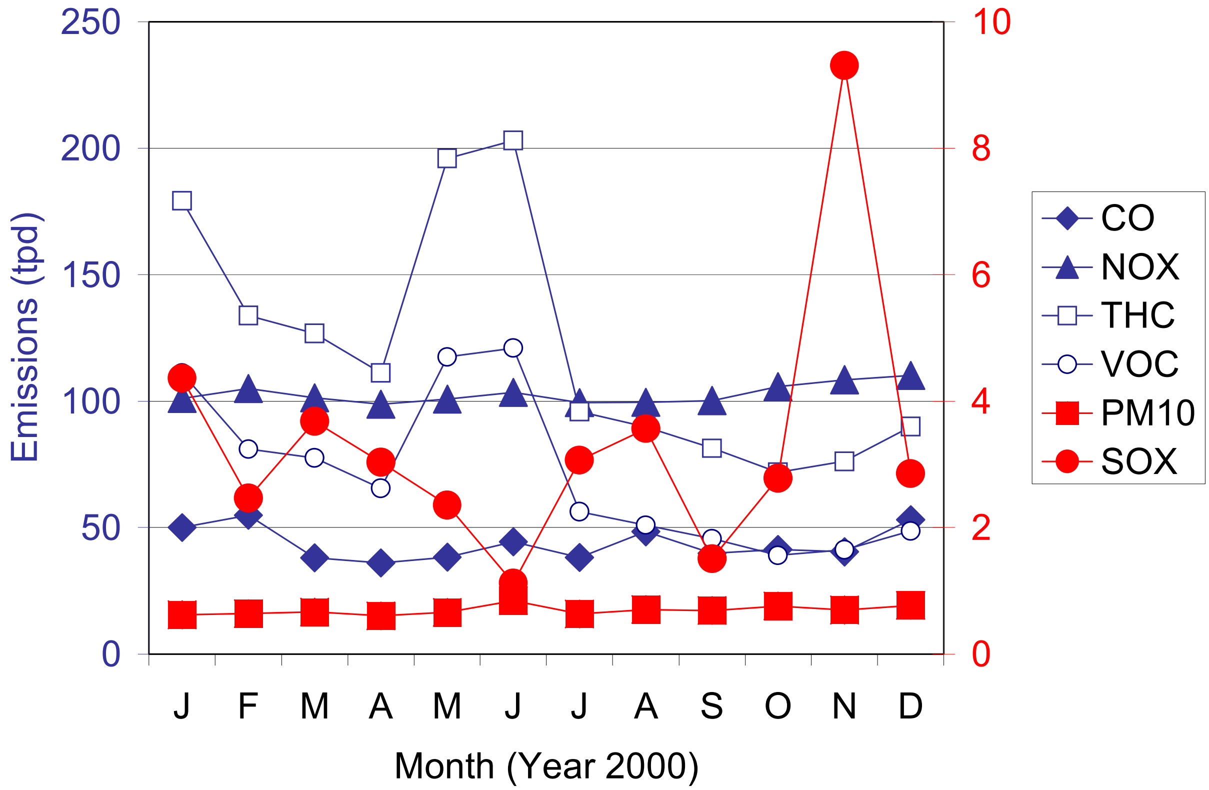
Figure 3-1 illustrates total monthly estimated emissions for all facilities that were represented in the electronic data reports submitted to the MMS. Estimated total emissions ranged from the monthly minima and maxima listed in **Table 3-1** for each pollutant. Several pollutants underwent large monthly variabilities, which were driven by upset events with emissions routed to vents and flares.

Table 3-2 summarizes the total numbers of active equipment or process units that were represented in the monthly data files. **Figures 3-2 through 3-7** illustrate the monthly variabilities in total emissions broken down by each type of equipment or process. Several interesting patterns are apparent in Figures 2 through 7. The large variabilities in emissions from vents and flares are obvious and are due almost entirely to upset events. Counter-intuitively, it also appears that CO, PM_{10}, and SO_x emissions from flares are decoupled because they reached peak levels at different times of the year. This decoupling is due to the fact that total emissions from flares are strongly dependent on the unique characteristics of any flares that experience upset conditions. CO emissions from flares are proportional to the total quantity of gas combusted in flares. SO_x emissions peak when large volumes of acid gas are combusted under upset conditions. PM_{10} emission rates depend not only on the total volume of gas flared, but also on the reported smoking conditions of flares operating under upset conditions.

Gasoline engines, which are associated with relatively high emission rates of CO, were used at only one individual platform during the months of January and February, which resulted in small peaks in the CO emissions for this type of equipment. Similarly, a small peak in CO emissions for drilling operations is observable in February, which was associated with the use of gasoline as fuel during a single drilling operation. Thus, in January and February alone, CO emissions from gasoline engines and drilling operations exceeded the CO emissions from flares.

Figure 3-8 illustrates the distribution of total annual emissions by pollutant and equipment type. From this figure, it is apparent that natural gas engines are the predominant source of NO_x emissions and flares are the predominant source of SO_x emissions. A variety of sources contribute to emissions of PM_{10}, THC, and VOC.

Figures 3-9 through 3-13 depict geographic distributions of air pollutant emissions for OCS facilities included in the year 2000 BNWA inventory.



Note: PM_{10} and SO_x are plotted on the right-hand scale. All other pollutants are plotted on the left-hand scale.

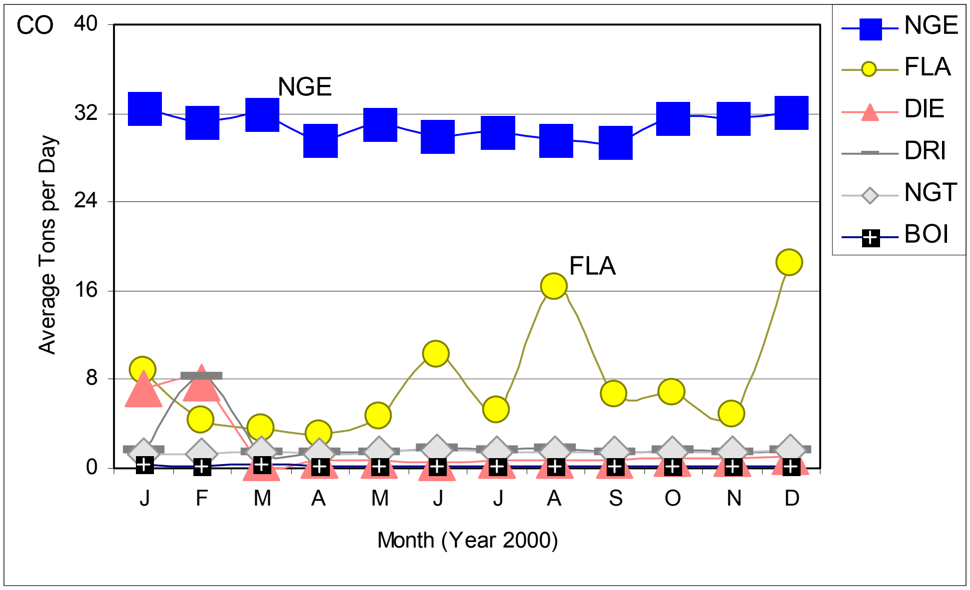
Figure 3-1. Monthly total emissions for OCS facilities included in the year 2000 BNWA emission inventory.

Table 3-1. Minimum and maximum monthly total emissions for OCS facilities included in the year 2000 BNWA emission inventory.

Air Pollutant	Minimum (tons/day)	Maximum (tons/day)
Carbon monoxide (CO)	36	55
Nitrogen oxides (NO_x)	99	110
Total hydrocarbons (THC)	72	203
Volatile organic compounds (VOC)	39	121
Particulate matter below 10 microns (PM_{10})	0.60	0.85
Sulfur oxides (SO_x)	1.1	9.3

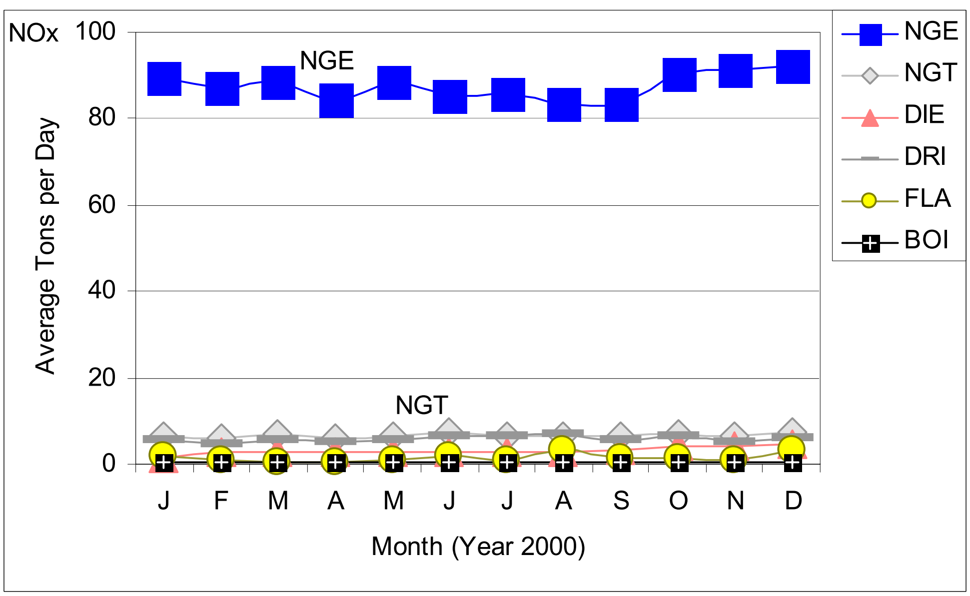
Table 3-2. Minimum, maximum, and average monthly counts of active equipment units or processes included in the year 2000 BNWA emission inventory.

Equipment or Process Type	Minimum (count)	Maximum (count)	Average (count)
Amine gas sweetening units	3	5	4
Boilers	110	131	121
Diesel or gasoline IC engines	616	645	631
Drilling operations	14	26	20
Flares	38	51	42
Platforms with fugitives	252	270	266
Glycol gas dehydrators	109	121	113
Loading operations	1	2	2
Natural gas engines	475	499	490
Natural gas turbines	133	140	136
Storage tanks	135	146	142
Vents	152	171	163
Total number of active OCS facilities	430	449	439



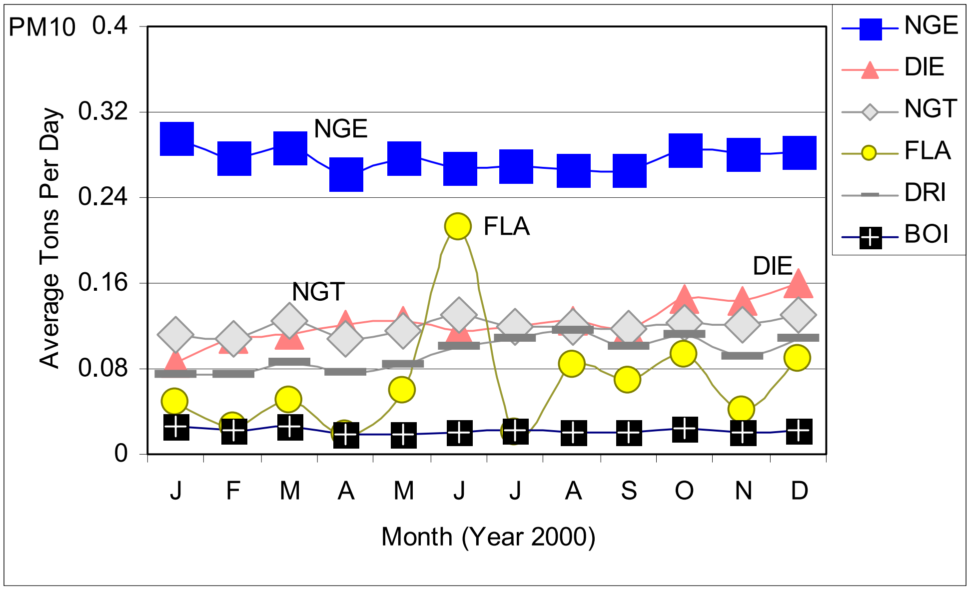
NGE = natural gas engines; FLA = flares; DIE = diesel or gasoline engines; DRI = drilling operations; NGT = natural gas turbines; BOI = boilers

Figure 3-2. Monthly total CO emissions by type of equipment or process for OCS facilities included in the year 2000 BNWA emission inventory.



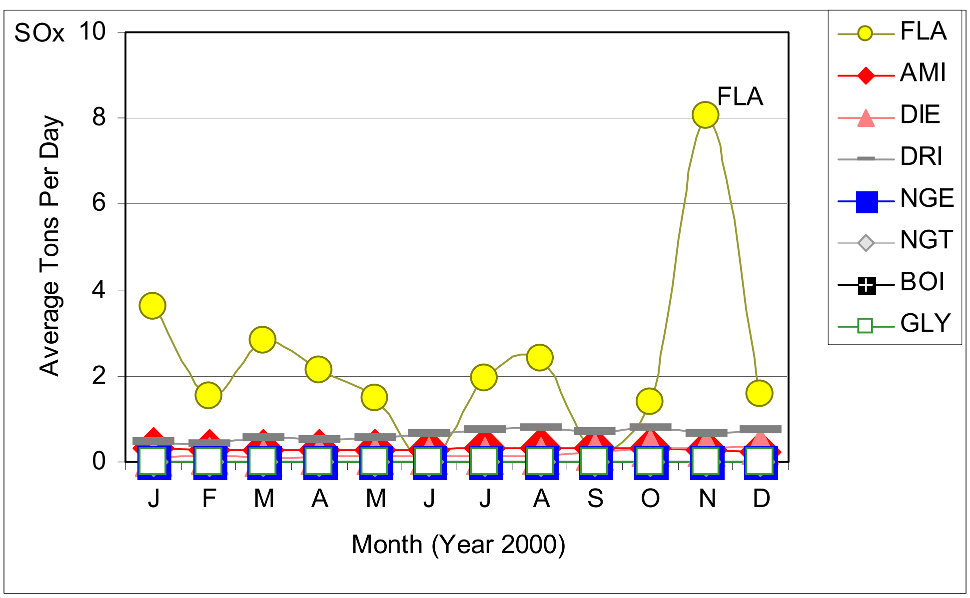
NGE = natural gas engines; FLA = flares; DIE = diesel or gasoline engines; DRI = drilling operations; NGT = natural gas turbines; BOI = boilers

Figure 3-3. Monthly total NO_x emissions by type of equipment or process for OCS facilities included in the year 2000 BNWA emission inventory.



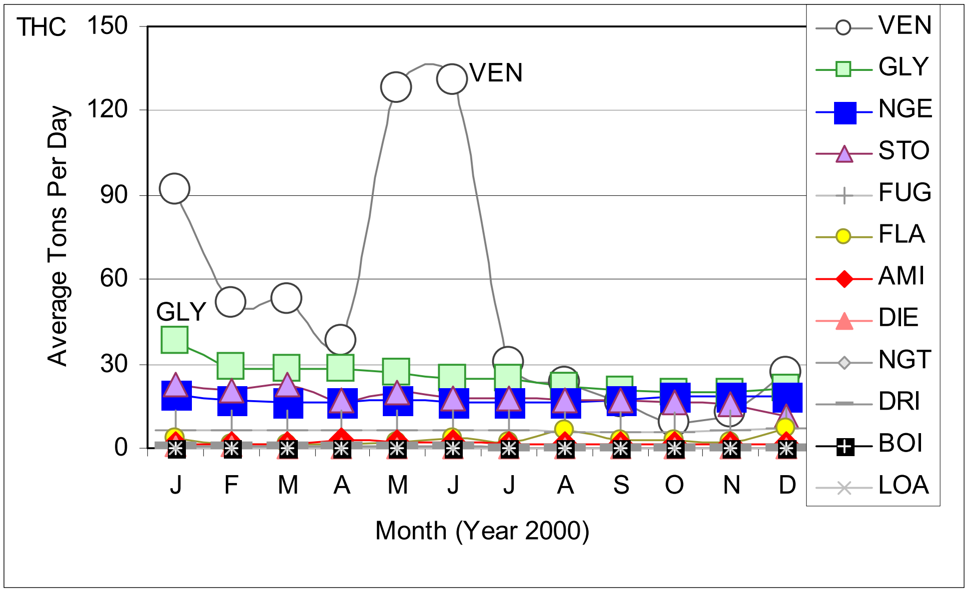
NGE = natural gas engines; DIE = diesel or gasoline engines; NGT = natural gas turbines; FLA = flares; DRI = drilling operations; BOI = boilers

Figure 3-4. Monthly total PM_{10} by type of equipment or process for OCS facilities included in the year 2000 BNWA emission inventory.



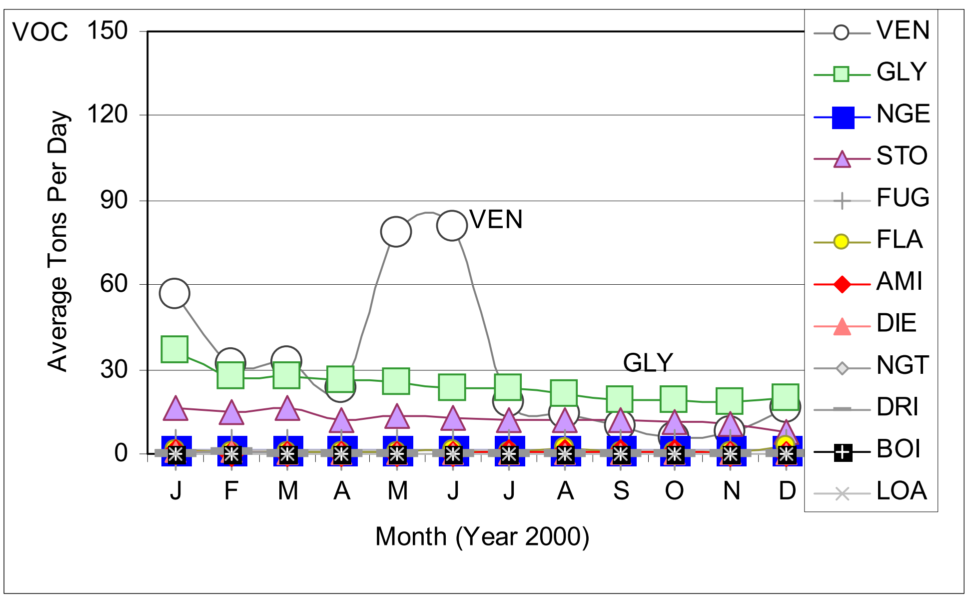
FLA = flares; AMI = amine gas sweetening units; DIE = diesel or gasoline engines; DRI = drilling operations; NGE = natural gas engines; NGT = natural gas turbines; BOI = boilers; GLY = glycol dehydrators

Figure 3-5. Monthly total SO_x emissions by type of equipment or process for OCS facilities included in the year 2000 BNWA emission inventory.



VEN = vents; GLY = glycol dehydrators; NGE = natural gas engines; STO = storage tanks; FUG = fugitives; FLA = flares; AMI = amine gas sweetening units; DIE = diesel or gasoline engines; NGT = natural gas turbines; DRI = drilling operations; BOI = boilers; LOA = loading operations

Figure 3-6. Monthly THC emissions by type of equipment or process for OCS facilities included in the year 2000 BNWA emission inventory.



VEN = vents; GLY = glycol dehydrators; NGE = natural gas engines; STO = storage tanks; FUG = fugitives; FLA = flares; AMI = amine gas sweetening units; DIE = diesel or gasoline engines; NGT = natural gas turbines; DRI = drilling operations; BOI = boilers; LOA = loading operations

Figure 3-7. Monthly total VOC emissions by type of equipment or process for OCS facilities included in the year 2000 BNWA emission inventory.

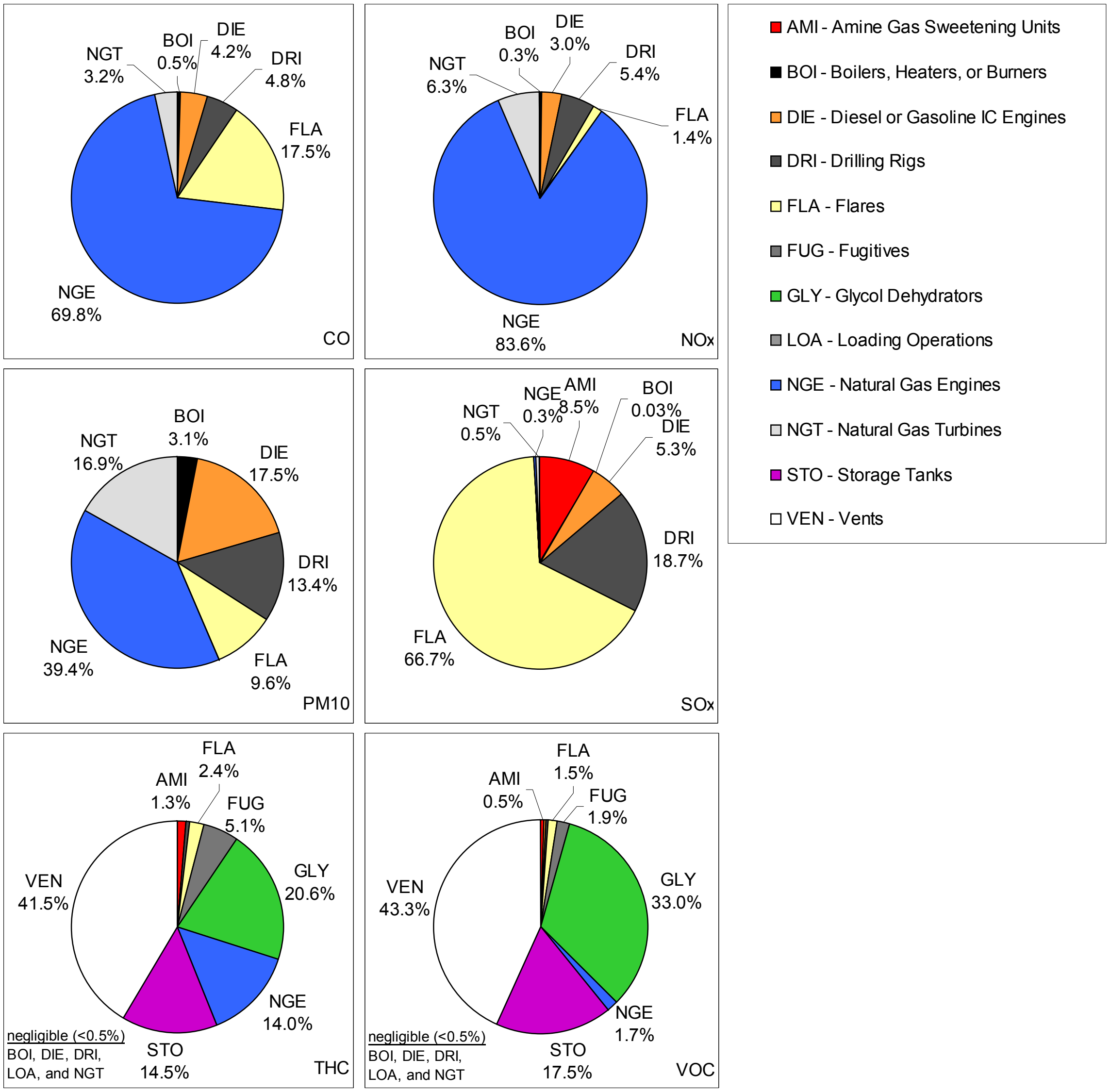


Figure 3-8. Distributions of annual total emissions for six pollutants by type of equipment or process for OCS facilities included in the year 2000 BNWA emission inventory.

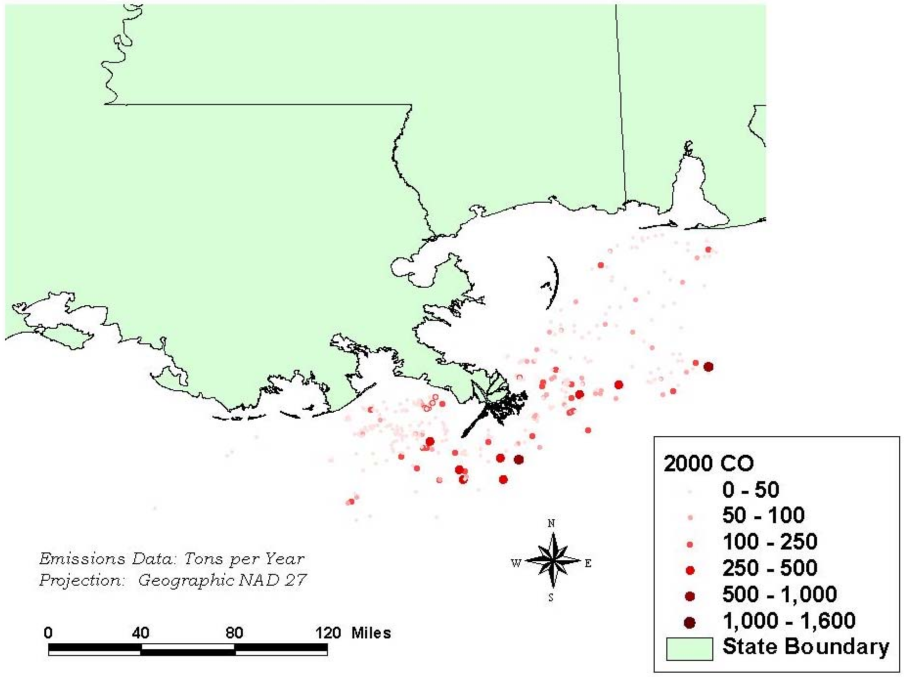


Figure 3-9. Geographic distribution of total annual CO emissions for OCS facilities included in the year 2000 BNWA emission inventory.

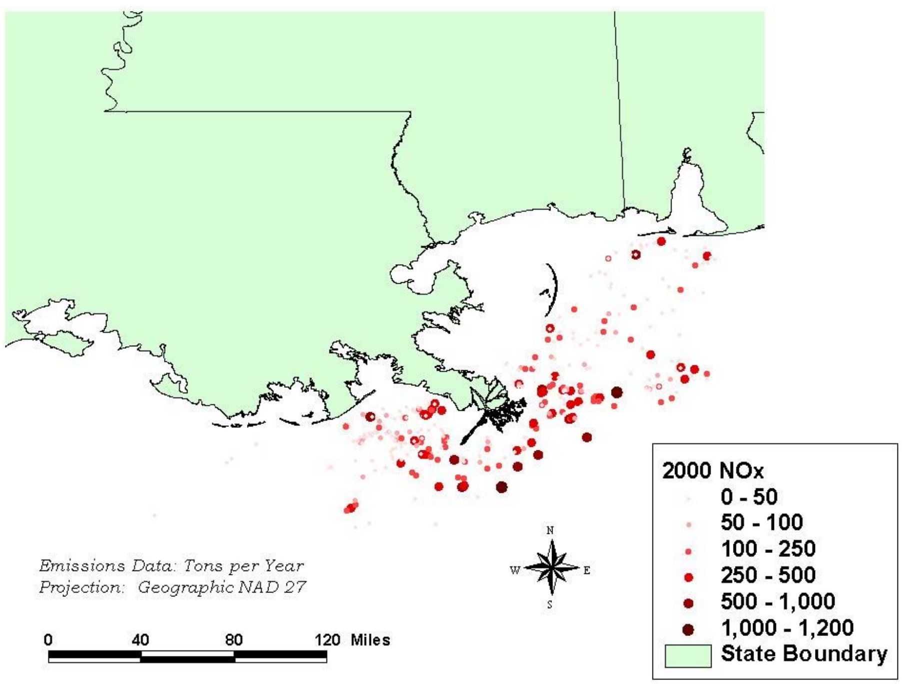


Figure 3-10. Geographic distribution of total annual NO_x emissions for OCS facilities included in the year 2000 BNWA emission inventory.

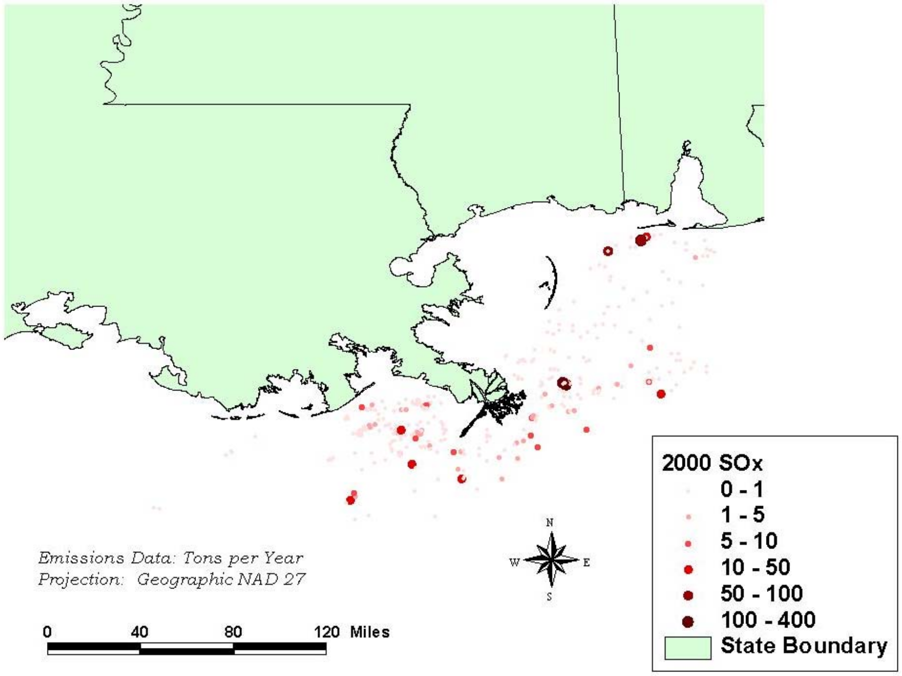


Figure 3-11. Geographic distribution of total annual SO_x emissions for OCS facilities included in the year 2000 BNWA emission inventory.

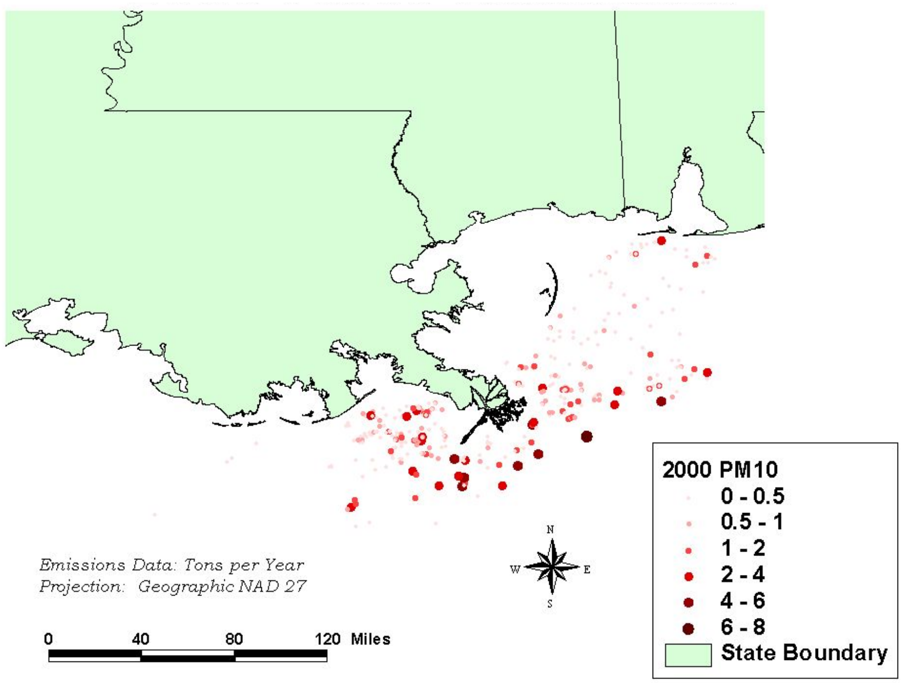


Figure 3-12. Geographic distribution of total annual PM_{10} for OCS facilities included in the year 2000 BNWA emission inventory.

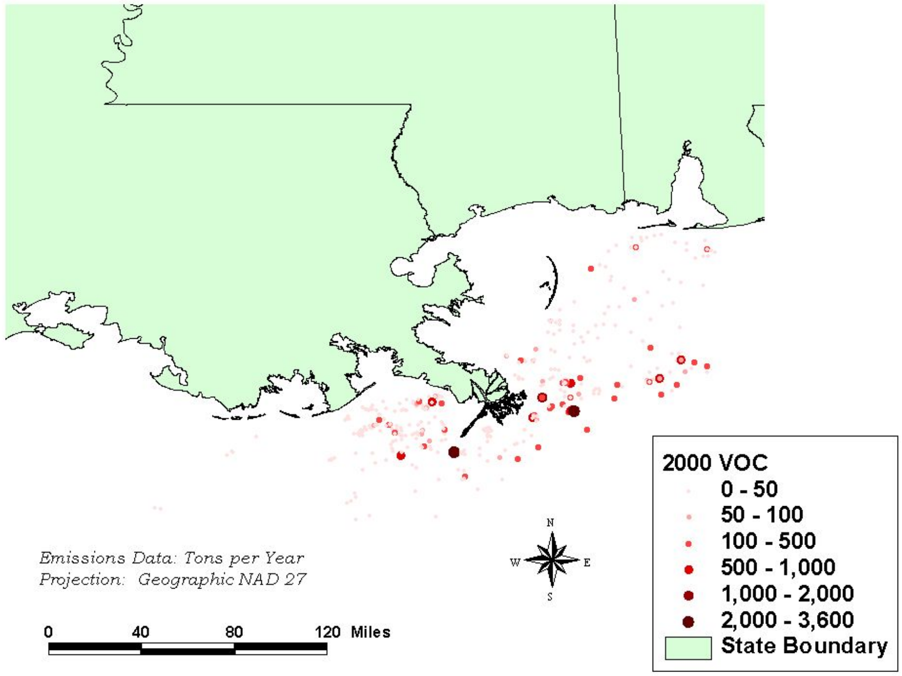


Figure 3-13. Geographic distribution of total annual VOC emissions for OCS facilities included in the year 2000 BNWA emission inventory.

4. REFERENCES

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APPENDIX A

PLATFORM ACTIVITY DATA SOURCES AND PROCESSING FOR ESTIMATING HISTORICAL EMISSIONS

The development of a historical emissions inventory for platform operations in the Gulf of Mexico required the use of many sources of data. This section describes sources of data and steps followed to develop the historical inventories.

MMS HISTORICAL ACTIVITY DATA

The Minerals Management Service (MMS) maintains considerable information on historical activity on the development and production of oil and gas in the Gulf of Mexico. Together with MMS staff, several key measures of historical activity were obtained for use in this study as described below.

Production Data

Production data for leases within the Gulf of Mexico for the years of 1977, 1988, and 2000 were obtained from MMS. In addition, data for years 1991 and 1992 were obtained to compare with production data used in the MOADS inventory, which took place from June 1991 to May 1992. Regardless of year, the production data records include: MMS lease number, number of active months, protraction block, area code, annual total barrels of oil produced by lease, and annual amount of natural gas produced by lease in thousand cubic feet. The protraction block and area code provide spatial information specific to each lease. It is important to note that the production data are provided for leases, which occupy a large area (typically 5,000 acres), as compared to the emissions inventory data, which are specific to individual platforms.

Platform Records

An electronic list of all platforms constructed in the Gulf of Mexico was supplied to STI. The file includes a unique platform id code called MMS ID (derived from concatenation of complex id and structure id), the lease number that the platform is in, operator number, area and block number (spatial information), installation and removal date, whether the platform is considered "major" or staffed 24 hours a day, water depth, and latitude and longitude. This file was primarily used to determine the construction-related emissions for the historical emission inventory; however, it also proved useful to spatially allocate emissions from leases to point specific locations. From the installation date, those platforms constructed during 1977 and 1988 were easily separated from the entire data set for estimation of emissions from construction activities. For those platforms constructed in either 1977 or 1988, we developed a matrix relating water depth and number of pilings (either actual or estimated) to equipment type and estimated amount of fuel used.

Borehole Data

Drilling emissions

The emissions associated with equipment used to drill the oil and gas wells was based on the MMS ASCII file "5010", which was downloaded from the MMS website on September 13, 2001. The file description was "All Borehole data by field". This file contains information about every “borehole” bored into the Gulf of Mexico since record-keeping began. There are two primary types of boreholes: experimental and developmental. As the emissions associated with exploratory drilling tend to be “mobile” they have been included in the mobile portion of the emission inventory and are discussed elsewhere. The borehole data file included: API well number, operator number, spud date (i.e. date drilling began), total depth date (date well reached total depth), well type code (e.g. exploratory or developmental), drilling depth information, Bottom lease number, area and block codes, and the latitude and longitude of the surface and bottom of the well. These data serve as the basis for the estimation of emissions resulting from drilling rigs during the years of the historical inventory.

The borehole data provided by MMS was used to develop emissions estimates of drilling activities. The “Spud Date” and “Total Depth Date” were used to calculate the length of drilling operations: called the “Drill Duration”. These data were quality controlled before being used to calculate emissions. About 95% of “Drill Duration,” ranged from 3 days to 185 days. However, several hundred drilling operations fell well outside this typical range of drilling duration. Therefore, it was decided to account for these activities’ emissions by assuming that they occurred with the average drilling duration, which is 43 days. The original start date was not modified, but the total depth date was re-calculated as being 43 days from the start date. In addition, some records were missing temporal information. Although the records with no temporal information represent a very small percent of the entire data set, if they all occurred in one year (say 1977 or 1988), it could have a significant impact on that year’s inventory. When the records that had missing temporal information were compared with an updated borehole file (downloaded June 3, 2002), it was apparent that most of the wells with missing dates in the original file were drilled in 2001 or 2002. These wells had not yet begun drilling at the time they were entered into the originally downloaded borehole data. As such, those wells with no temporal information were assumed to be wells that were not active during the historical emissions inventory years.

Mud Degassing

The borehole data obtained from MMS are also the basis for the estimation of mud degassing emissions. A source of emissions that occurs concurrent with borehole drilling activity is the release of gases that have been dissolved in the mud of the ocean floor. This process is referred to as “mud degassing”. Unlike emissions associated with drilling equipment, the release of gases entrained in the sea mud are likely to occur in the vicinity of the borehole and are considered a part of the stationary source inventory. As such, mud-degassing emissions were estimated for all boreholes (as opposed to only developmental wells) drilled during the years of the inventory.

<u>OGOR-B</u>

“Oil and Gas Operations Report” List B (OGOR-B) is an annual “inventory” of oil and gas extracted from federal lands. The detailed information contained in this report includes monthly lease specific data about amount of oil and gas sold, vented or flared, or used on the platforms for energy generation, as well as many other classifications. The level of detail found in these reports is particularly useful for trend extrapolation and backcasting of historical activities where no other data is available. STI obtained OGOR-B reports for years 1985-2000 from MMS. It is important to note that the OGOR-B reports are not available for any year prior to 1985. Thus, we derived data for 1977 by extrapolating available data.

The only processing required for the OGOR-B files was the conversion of "Unit Agreement Numbers" into their composite leases using MMS file 4600, "Pbunitas.dat". The information associated with Unit Agreement Numbers was divided into the appropriate leases by one of two methods. The Unit Agreement file 4600 intermittently lists the percent of each lease's contribution to Unit Agreement production. In this case the OGOR-B unit agreement data was apportioned to each lease based on their indicated percentage. If the unit agreement file had no percentages indicated, then the OGOR-B data was apportioned evenly among all applicable leases.

Natural gas used on platforms

The OGOR-B file has "disposition codes" which indicate the activity type of the associated information. The Disposition code 20 is defined as "reported products used on, or for the benefit of, Lease/Agreement operations with prior approval from BLM or OMM (e.g. Lease/Agreement gas used to operate production facilities)". The information contained in OGOR-B reports for disposition code 20 was used to determine the quantity of natural gas reported used on leases over the last 15 years in the Gulf of Mexico. The amount of natural gas used on the leases is considered to have been for equipment operation and was used to estimate yearly and monthly variations in natural gas use. **Table A-1** lists the reported consumption of natural gas for lease operations by year as generated from the OGOR-B reports.

Table A-1. OGOR-B reported natural gas use for platform operations by year.

Year	OGOR-B reported natural gas used (dis. code=20)
2000	109,222,260 Mcf
1991-92	90,618,695 Mcf
1988	84,141,550 Mcf
1977[a]	66,521,815 Mcf

[a] The following equation was used to estimate the amount of natural gas used in 1977. This equation was derived from a trend regression of natural gas used as a function of natural gas produced for data in 1985 through 2000.

Percent NG used = (1.83417E-10 × NG produced + 1.075%) ÷ 100%

NG used77 = (1.83417E-10 × NG produced + 1.075%) ÷ 100% × 3,766,717,354 (Mcf)

NG used77 = 1.766% × 3,766,717,354 (Mcf) = 66,521,815 Mcf

Natural gas vented and flared

Venting and flaring activities are reported in OGOR-B reports under disposition codes 21 and 22. These codes are defined respectively as "Reported flared or vented casinghead gas" and "reported well gas that was flared or vented". The level of detail in the OGOR-B reports regarding venting and flaring activities is the most specific information found, yet it is still too general for accurate estimation of emissions as the quantity of gas vented and flared are reported in aggregate.

The data in the OGOR-B reports was used in conjunction with production information to generate Gulf specific venting and flaring trends. The amount of gas vented and flared from oil wells and gas wells was summed together to generate total gas released. Total gas released was divided by gas produced to understand how release rates vary as a function of time and production. From the results of these analyses an estimate of total natural gas released in 1977 was developed. **Table A-2** summarizes the amount of natural gas reportedly sent to vents and flares in the OGOR-B reports and the amount estimated for 1977.

Table A-2. The sum of OGOR-B reported natural gas vented and flared by year.

Year	Natural gas vented and flared from OGOR-B (MCF)	Percent of total natural gas production
2000	12,834,605 Mcf	0.259
1991-92	11,924,751 Mcf	0.255
1988	16,869,964 Mcf	0.369
1977[a]	33,814,584 Mcf	0.898

[a] Note this represents an estimate based on regression analyses.

GIS map layers

ArcView GIS software was used to develop spatial relationships between the emissions inventory and geographical features in the Gulf of Mexico and for QC purposes. The initial GIS data layers were obtained from the MMS and included land and water boundaries, gridded ocean blocks and corresponding areas, protraction blocks, bathymetry lines, and active leases. The spatial analysis software in GIS helped to further identify the region that was 100 km from the Breton National Wildlife Refuge.

AVAILABLE EMISSION INVENTORIES

MOADS 3

The existing Gulf-wide emissions inventory, MOADS 3, was used as the basis for the historical inventories. It was originally developed for the Gulf of Mexico Air Quality Study (GMAQ) in 1993. The MOADS 3 emissions inventory was compiled from surveys of platform equipment operations in the Gulf of Mexico from June 1991 through May 1992. Note that MOADS 3 only includes emissions generated by platform sources. Therefore, alternative data sources were used to generate historical emissions for drilling equipment and platform construction rigs as will be discussed later.

During our initial review of MOADS 3, we found that the MOADS 3 inventory was not complete for all platform equipment activity. The equipment types included in the MOADS 3 inventory are listed by SCC code in Table A-3 and include platform engines (both natural gas and diesel powered), turbines, and boilers, as well as venting and flaring equipment, and storage tanks for diesel and crude oil. Emissions from the operation of gas processing equipment (glycol units, amine sweeteners, and appurtenance platforms) were not included in the MOADS 3 inventory. (Appurtenance platforms are processing-only platforms; they report no production of oil or gas, but could contribute emissions from processing equipment.) The significance of the emissions from appurtenance platforms has not been documented; however, it is our understanding that appurtenance platforms were virtually non-existent in 1977, but have since grown in importance as explained by Dr. Richard Karp of MMS.

Table A-3. Emissions sources included in the MOADS 3.

SCC Code	Description	Number of Occurrences	Activity Code
10200501	Industrial External Combustion Boiler: Distillate Oil	1	BOI
10200601	Large Industrial External Combustion Boiler: natural Gas	35	BOI
10200602	Medium Industrial External Combustion Boiler: natural Gas	27	BOI
10200603	Small Industrial External Combustion Boiler: natural Gas	603	BOI
20200101	Industrial Diesel Turbine	5	DIE
20200102	Industrial Internal Combustion Engine: Diesel	2,634	DIE
20200201	Industrial natural Gas Turbine	345	NGT
20200202	Industrial Internal Combustion Engine: natural gas	2,263	NGE
20200401	Large Bore Internal Combustion Engine: Diesel	48	DIE
31000205	Industrial natural Gas Flare	78	FLA
40301010	Breathing Loss from Crude Oil Storage Tanks	629	STO
40301012	Working Loss from Crude Oil Storage Tanks	629	STO
40301019	Breathing Loss from Diesel Storage Tanks	1097	STO
40301021	Breathing Loss from Diesel Storage Tanks	1097	STO
99000030	Vent	675	GV

To assess MOADS 3, we compared a subset of the inventory to the recently completed current-year emissions inventory for the BNWA. The BNWA inventory includes the emissions from only the area within 100 kilometers of the BNWA. This QC process revealed several inconsistencies between the two inventories. The primary differences included (1) emission factor differences, (2) natural gas engine type distribution, (3) emissions of SO_x and PM from flaring activities, and (4) VOC emissions from all sources. We found that several of the platforms included in the MOADS inventory were not installed at that time according to the MMS records. The MOADS 3 emissions inventory was compiled from surveys performed from June 1991 until the end of May 1992. A list of these platforms that have inconsistencies with the platform information provided by MMS is provided in **Table A-4**. We used MOADS platform records as is and did not make any changes to MOADS platform records to account for these discrepancies.

Table A-4. Platforms in MOADS 3 with discrepancies with MMS records.

MMS_ID	SHORT_ID (in historical database)	INSTALL_DATE	REMOVAL_DATE
21405_4	1085	1/1/93	Null
24142_1	2426	6/11/93	Null
21405_1	1082	12/8/93	Null
23820_1	2882	12/12/92	9/8/00
20045_1	413	12/6/94	Null
24084_1	2911	5/5/94	7/13/99
22444_1	1750	2/15/98	Null
21613_1	2761	1/1/61	12/31/75

To accurately gage the difference between the two inventories' estimated emissions, the inventories first had to be normalized to account for variations in activity level (e.g. if there was more production in year 2000 than in 1993, there could be more emissions). This inventory normalization revealed that the two inventories had been developed with different emission factors; the BNWA inventory had been developed with the recently updated EPA emission factors for many equipment types used on platforms.

As shown in Table A-2 above, natural gas engines represent a sizable portion of the platform equipment. Within the category of natural gas reciprocal engines there are many types and sizes of engines with a large variation of emission factors for NO_x, CO, THC, VOC, and PM. Thus, the distribution pattern of these natural gas engines types can have a significant impact on the emission inventory. The engine type distribution can be especially important because NO_x and CO emissions from natural gas engines represent about 87% and 80% (respectively) by weight of the emissions for the total platform source inventory. From the available MOADS 3 inventory documentation, the assignment of emission factors was based on an assumed distribution of natural gas engine types (Systems Applications International, 1995. Appendix N-12). The MOADS 3 natural gas engine distribution varied significantly from the BOADS inventory, which was based on recent survey data.

Another notable difference between the two inventories is the discrepancy between SO_x emissions resulting from flaring equipment. The MOADS inventory reports that SO_x emissions are three orders of magnitude lower than that reported by BOADS inventory, on a per volume flared basis (this difference was associated with a very low sulfur content assumed in natural gas sent to flares in the MOAD 3 inventory). Additionally, we found that particulate emissions associated with flares were not included in MOADS 3 (Systems Applications International, 1995); although relatively low, particulate emissions can be expected to occur with the operation of flaring equipment. Finally, after examining MOADS 3's supporting documentation, we found that in the MOADS 3 inventory THC was mislabeled as VOC.

As a result of the review and QC process several adjustments were made to the original MOADS 3 inventory prior to its use in preparing scaled backcast emissions. The MOADS 3 inventory was modified first by revising the distribution of natural gas engine types and updating all platform equipment emission factors. (Before using the new EPA emission factors, we confirmed that the EPA's new emission factors were not the result of changes in technology.) SO_x emissions from flaring were revised based on the average H_2S concentration of non-upset flared natural gas as reported in the BOADS inventory (versus an assumed concentration in the original MOADS 3). The relative ratio of gases vented to gases flared was adjusted as described on pages A-20 through A-22. Finally, PM emissions from flaring were incorporated into the MOADS 3 inventory based on BOADS inventory's frequency of flares operating with smoke conditions. Combined these modifications to the original MOADS 3 inventory had a significant impact on the total emissions. The most important modification in terms of net emissions change was incorporating updated AP-42 emission factors. The original MOADS 3 emissions are summarized in **Table A-5**. These can be compared to **Table A-6**, which lists the emissions inventory resulting from the modifications listed above.

Table A-5. The original MOADS 3 inventory.

Activity Type	Emissions (tons/year)					
	NO_x	THC	VOC	CO	SOx	PM
Engines, Turbines, or Boilers	93,131	38,255	N/A	21,318	182	1,725
Gas vented or flared	104	229,336	N/A	567	0.44	0
Storage tanks	-	10,579	N/A	-	-	-
Original Total	93,235	278,170	N/A	21,885	182	1,725

N/A Not available

Table A-6. MOADS 3 inventory after modifications.

Activity Type	Revised Emissions (tons/year)					
	NO_x	THC	VOC	CO	SOx	PM
Engines, Turbines, or Boilers	78,936	21,511	1,500	104,346	182	619
Gas vented or flared	153	169,099	9,456	834	1,454	2
Storage tanks	-	10,579	9,822	-	-	-
Revised Total	79,089	201,189	20,778	105,180	1,639	621

The change in emissions from engines, turbines and boilers on platforms is due to two adjustments: an updated distribution of natural gas reciprocal engine types and updated emission factors. Under the SCC category "natural gas reciprocating engines" there are currently six different sub-categories, all of which have different emission factors. In the MOADS 3 inventory, the assumed natural gas engine distribution was 66% 2-stroke engines, 16.7% 4-stroke lean burn, and 16.7% 4-stroke rich burn. From the BOADS survey results, the sampled platforms reported a very different engine distribution than that assumed in MOADS 3; the majority of platforms operate a 4-stroke engine, only 7% of the respondents indicated 2-stroke engine operations, 8% of engines were 4-stoke clean burn, 11% were 4-stoke lean burning, and the remaining 74% of engines were 4-stroke rich burn. The application of a revised distribution resulted in a substantial increase of CO emissions, while NO_x, THC, VOC and PM were only slightly reduced. **Table A-7** shows the 1990 emission factors (SAI, 1995; EPA, 2000a) and year 2000 emission factors for each natural gas engine type, the different inventory distributions, and weighted total emission factors used in the BOADS inventory effort.

Table A-7. Natural Gas Engine Usage and Emission Factors

Year	Units	Engine Type	Emission Factors by Engine Type						Distribution Percentage
			CO	NO_x	SO_x [c]	THC	VOC [d]	TSP	
1990	lbs/MMcf	2-stroke lean	399	2835	0.3	1575	115.5		66.67
1990	lbs/MMcf	4-stroke lean	441	3360	0.3	1365	189		16.67
1990	lbs/MMcf	4-stroke rich	1680	2415	0.3	283.5	31.5		16.67
MOADS Emission Factors [a]	**lbs/MMcf**	**Weighted Total**	**620**	**2850**	**0.3**	**1300**	**100**	**35**	**100**
2000[b]	lbs/MMcf	2-Cycle Clean	405	140	N/A	1900	285	29	1
2000[b]	lbs/MMcf	2-Cycle Lean	400	3300	N/A	1700	125	10	3
2000[b]	lbs/MMcf	2-Cycle Rich	1800	4400	N/A	350	29	13	3
2000[b]	lbs/MMcf	4-Cycle Clean	530	130	N/A	2600	92	17	8
2000[b]	lbs/MMcf	4-Cycle Lean	330	4280	N/A	1500	120	10	11
2000[b]	lbs/MMcf	4-Cycle Rich	3900	2300	N/A	375	31	10	74
2000	**lbs/MMcf**	**Weighted Total**	**3035**	**2415**	**N/A**	**731**	**51**	**11**	**100**
Ratio of New Emission Factors to MOADS Old Emission Factors		Ratio Used to Adjust MOADS	4.89	0.85	N/A	0.56	N/A	0.31	

[a] Weighted average emission factors used for natural gas engines, Systems Applications International Report (1995).
[b] Year 2000 emission factors from EPA AP-42 Compilation of Emission Factors Chapter 3.2 (2000a).
[c] SO_x emissions are computed by using an assumed average sulfur fuel content of 2,000 grains/scf.
[d] VOC emissions estimated by the ratio of VOC to THC emissions from natural gas engines.

BNWA INVENTORY

As noted above, the MOADS inventory was adjusted to incorporate newly available information acquired from a survey of the production platforms within 100 km of the Breton National Wildlife Area (BNWA). The BNWA Inventory was compared to a sub-set of the MOADS inventory. Below we describe the adjustment to the MOADS based on the BNWA emissions inventory.

Glycol Unit Activity

From the surveys of platform operations, glycol unit activity as a function of natural gas production was determined. After the BOADS inventory results were quality controlled, the amount of gas processed by Glycol units was essentially 100% of that produced in year 2000. We then assumed that this relationship was valid historically, since glycol unit operation is necessary to maintain proper pipeline integrity.

The emission factors used to estimate emissions from glycol activity were from a combination of Louisiana State survey results and GRI-GlyCalc software. Emissions of VOCs are based upon an emission factor derived from a survey of facilities that was conducted by the Louisiana DEQ in 1991 (personal communication with D. Scalfano, Northlake Engineers and Surveyors, Inc., Mandeville, LA, 2001). Emissions of THC are extrapolated from molar glycol affinities (THC:VOC) that were modeled using GRI-GlyCalc. Emissions are highly dependent upon the type of glycol used in the dehydrator unit and Triethylene Glycol was used in almost 100% of all platforms surveyed.

Venting and Flaring Inventory

Readily available data such as the OGOR-B reports do not differentiate the proportion of gas diverted to venting versus flaring. From an emissions standpoint there is a considerable difference between the combustion by-products of natural gas (flares) and the release of natural gases to the atmosphere (vents). Therefore we determined the split from the detailed survey results from MOADS and BOADS. One draw back of this process is that the information is limited to only two time-periods: 1991-92 and 2000-01. Another draw back is that the information for BOADS is limited to a small sub-section of the entire Gulf of Mexico and as such Gulf-wide variation can only be assumed. However, this uncertainty was reduced by selecting those platforms within a 100 km of the Breton area from the MOADS inventory using ArcView GIS tools and comparing the two inventories directly. The results of this comparison are summarized below in **Table A-8**.

Table A-8. Natural gas vented and flared in MOADS and BOADS.

Inventory Activity	Data restricted to Breton Area		Gulf-wide Data
	BOADS (2000)	MOADS (1993)	Total MOADS inventory (1993)
Volume Flared (MCF/year)	2,290,986	1,636,660	2,921,825
Volume Vented (MCF/year)	4,469,993	3,894,364	9,751,877
Total Natural Gas Released (MCF/year)	6,760,979	5,531,024	12,673,702
Percent Flared:	33.9	29.6	23.1
Percent Vented:	66.1	70.4	76.9
Ratio of Gas Flared to Gas Vented:	0.51	0.42	0.30

Gas with high H_2S content must be flared for safety reasons. Although the H_2S content was not quantified for the Breton Area, the Breton area could have a disproportionately higher amount of flaring activities since the H_2S content of gas is documented to be high in nearby Mobile, Alabama and other pockets close to the coastline (EPA, 1995; Corbeille, 1997). This assumption is supported by comparing the percentage of gas flared in the MOADS inventory, restricted to Breton Area, to the MOADS gulf-wide inventory. The MOADS data in the Breton area for percentage flared is approximately 30% of the total volume of gas released, where as the gulf-wide percentage is 23%.

The results of the BOADS inventory surveys were used to replace the national default values used in MOADS for sulfur content and smokeless flaring conditions. The weighted average H_2S content in the BOADS inventory was between 3000 and 5250 ppmv for natural gas sent to flares. The midpoint of this range (4100 ppmv) was used to estimate the amount of H_2S typically sent to flares in the adjusted MOADS inventory. Although this value seems high, it is still an order of magnitude smaller than the sulfur content the EPA reported for natural gas extracted from Mobile, Alabama (EPA, 1995). We recognize that the BOADS inventory average H_2S content may be higher than that found on average Gulf-wide; however, use of the BOADS average H_2S content provides a conservatively high SO_x emissions estimate for the historical inventory. The particulate matter emitted from smoky flares was also indirectly surveyed in the BOADS inventory. The survey results combined with EPA emission factors provided an average emission factor for all flares operated: 9.4×10^{-4} lb/MMBtu (assuming an average natural gas heating value of 1050 Btu/scf).

METHODOLOGY

WELL DRILLING EMISSIONS

Drilling Equipment Emissions

The methodology used to estimate emissions for this source relied on borehole data from MMS. Daily fuel consumption was based on a survey of actual fuel consumption during drilling rig operations. The predominate drilling rig used was a "Jackup" Drill. Fuel consumption was based on a weighted average of this drill and two others. The average fuel use plus one standard deviation is 2256 gallons of diesel fuel/day of drilling; this value is used to provide a conservatively high estimate of the total fuel consumption. The amount of fuel consumed was estimated based on calculated daily fuel consumption times the number of drilling days. The estimated fuel consumption was combined with appropriate emission factors (EPA AP42) to calculate the emissions from drilling.

The EPA background document for large engines provides the uncontrolled emission factors, which are particularly relevant to the estimation of historical emissions (EPA, 2001). **Table A-9** lists the emission factors used to estimate emissions from total diesel fuel consumption during drilling. The amount of diesel fuel consumed was converted to quantity of energy used by multiplying the number of gallons by 7.1 lbs/gallon and then multiplying pounds by 19,300 Btu/lb and finally, converting this to the appropriate units to use the emission factors below.

Table A-9. Uncontrolled Emission Factors for Drilling Rig Equipment (EPA, 2001).

Emission Type	Emission Factor (lbs/MMBtu)
NO_x	3.2
CO	0.85
SO_x [a]	0.404
THC	0.09
VOC	0.0792
PM	0.0697
PM_{10}	0.0573
$PM_{2.5}$	0.0479

[a] Sulfur content of marine diesel fuel was estimated to be 0.4%.
For the calculation of the SO_x emission factor S = 0.4 * 1.01

Mud Degassing

Part of the mud degassing emissions estimation process required the calculation of the total depth drilled. True Vertical Depth is reported to be "The vertical distance, in feet, from the rig kelly bushing to the maximum depth of the well." To determine the total well depth, the distance from the rig kelly bushing to the water and the surface of the water to the ocean floor needs to be subtracted from the reported True Vertical Depth. The surface of the water to the ocean floor is the reported "water depth", and the distance from the rig kelly bushing to the water surface is named the "RKB elevation". The total depth drilled was calculated by subtracting the values for reported water depth and RKB Elevation from True Vertical Depth. The total depth was then used to determine the volume of mud displaced by the drilling activities. The volume was calculated based on the assumption that a drill bit of 3 inch (or use a quarter of a foot) radius was used and the volume displaced was cylindrical in shape. Thus, the total volume displaced was equivalent to pi*r^2 multiplied by the drilled depth, in feet. The average amount of gas dissolved in the mud is referenced to be as high as 63 cubic feet of gas per cubic foot of mud (EPA, 1977). The speciation profile for natural gas released from mud is undocumented; however, even if the VOC content of the gas was as high as 10%, it would still be an insignificant source of VOC relative to the rest of the inventory. Based on this, the VOC emissions from mud degassing are not incorporated into the inventory and it is assumed that the gas released is all THC. The molecular weight of THC combined with the referenced amount of gas released produces the emission factor of 2.71 lbs THC/cubic foot of mud displaced.

Spatial and Temporal Allocation

Once the emissions were estimated, they were spatially and temporally allocated based on the borehole data supplied by MMS. The borehole data provided spatial information for each borehole drilled by indicating surface coordinates in latitude and longitude. The surface latitude and longitude of each borehole were used to spatially allocate the emissions associated with drilling operations. Since the borehole data was day-specific, the emissions were temporally allocated to months of the year based on the number of drilling days in each month. For instance, if the "spud date" was August 27 and the "Total Depth Date" was September 10, then the number of drilling days in August would be five and September would be ten. The total emissions were allocated to each month by dividing the total number of drilling days, in this case 15, by the number of drilling days in a month. One third of the emissions would be allocated to the month of August and two thirds would be allocated to September, with the methodology used to temporally allocate drilling emissions.

PLATFORM CONSTRUCTION EMISSIONS

The data for the estimation of emissions from platform construction activities is derived from the MMS-supplied platform list and actual construction equipment fuel consumption data. The information about the number of platforms constructed in a given year is based on the "installation date" provided for each platform documented by MMS. For the majority of the early platforms, the installation date indicated the platform was installed on the first of the year for every platform. This does not provide enough information to determine temporal variation for the construction emissions; however, it is sufficient to determine which platforms were constructed in the inventory years: 1988, 1977. Relevant information also includes latitude and longitude of the platform and water depth.

The method used to estimate fuel consumption for platform construction equipment is a function of water depth and number of platform pilings. Water depth dictates the type of equipment used and the average daily fuel consumption. Then the number of pilings is an indication of the platform size. The more pilings the more days the construction will take. The estimated number of days is multiplied by the estimated daily fuel consumption to generate total fuel consumption.

We developed a methodology to determine fuel consumption based on water depth and actual or estimated number of pilings. Actual number of pilings was confirmed from digital photos from the MMS, when available. For those platforms without available photos, estimated number of pilings was determined from team member's experience and from consultation with Mr. Tommy Laurendine of the MMS platform group. In addition, Mr. Mac McDonald with McDermott Marine provided fuel consumption numbers for different platform types as shown in **Table A-10**. He assisted us in determining installation duration for different size platforms, platform size established by number of pilings (see **Table A-11**). Then, the average daily fuel consumption was multiplied by the installation duration to arrive at total fuel use for each platform. Emissions from construction activities are determined by multiplying fuel consumption values by the emission factors for Large Stationary Diesel Engines in Chapter 3.4 of AP-42. An average heating value of diesel fuel is assumed to be 19,300 Btu/lb with a density of 7.1 lb/gallon. The emission factors for uncontrolled NO_x were used with the understanding that most regulation was not implemented in the GOM until after the historical inventory years.

Table A-10. Estimated daily diesel fuel consumption for platform construction activities.

Daily Fuel Consumption of Marine Construction Equipment (gal)			
Equipment Type	Water Depth (ft)		
	< 300 ft	300 - 600 ft	< 600 ft
Deck Barge (various sizes)	1,514	1,514	7,919
135" Crewboat	2,907	2,907	2,907
180" Supplyboat	2,735	2,735	2,735
Tugboat (various Hp)	1,367	2,790	5,323
Total Estimated Fuel (gal/day)	**8,523**	**9,946**	**18,884**

Table A-11. Installation duration of platforms as a function of water depth and size.

Installation Duration per Platform (days)			
Number of Platform Pilings	Water Depth (ft)		
	< 300 ft	300 - 600 ft	< 600 ft
Caisson	6		
3 Pile	9		
4 Pile	10	19	38
6 Pile	14	26	52
8 Pile	18	33	66
16 Pile	30		

Spatial and Temporal Allocation

The spatial and temporal allocations of the emissions from platform construction equipment were distributed by the information provided in the platform list from MMS. The platform list indicated the latitude and longitude of the platforms, as well as the installation date. We treated construction barges as point sources, since they maintain their locations within 100 ft of a platform. Thus, the emissions from construction equipment are spatially allocated to the coordinates of the platform. The temporal distribution for emissions activities are considered to be seasonally dependant and the following monthly allocations were assumed (see **Table A-12**) based on seasonal variability.

Table A-12. Temporal Allocation for platform construction emissions.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Percentage of Annual Activity	3	3	7	7	7	10	15	15	15	10	5	3

PLATFORM EQUIPMENT EMISSIONS

Engines, Turbines, and Boilers

Emissions from platform engines, turbines, and boilers are apportioned to leases based on the annual lease production data provided by MMS. Without month specific production data, annual emissions were temporally allocated evenly to each month. It is recognized that the monthly distribution can have a large variation. However, there is not a significant seasonal pattern: platform and lease monthly production variation is fairly random.

Nitrogen Oxides, Carbon Monoxide, Total Hydrocarbons and Volatile Organic Compounds:

NO_x and CO: As discussed previously NO_x and CO emissions from natural gas engines represent over 85% of the emissions from non-flare, combustion equipment on platforms (e.g. reciprocating engines, turbines, and boilers). As natural gas engines' emissions represent a large fraction of the total platform equipment emissions, all NO_x emissions from non-flare, combustion equipment are grouped together and scaled from natural gas combustion activity. The NO_x emissions from these equipment (adjusted MOADS 3 values) are scaled historically according to reported quantity of natural gas used. Analysis of natural gas use as a function of production revealed that natural gas use is directly proportional to natural gas extraction. Also of interest is that in 2000, the price of natural gas was at record highs. Even when the market price of gas was high the percent of natural gas used on platforms still increased proportionally with natural gas extraction. Thus, the amount of natural gas used as fuel on the platforms is directly proportional to extraction and relatively independent of market value: a fact which makes it a good activity surrogate for platform equipment emissions. MOADS emissions were scaled as shown below to estimate historical inventories.

$$\text{Emis(yr)} = \text{Emis}_{\text{MOADS}} \times \text{NGused(yr)} \div \text{NGused}_{\text{MOADS}}$$

The ratio of natural gas used in 1988 to natural gas used in 1991-92 was 0.9285, or a decrease of 7.25%. This estimated change in natural gas use is multiplied by the adjusted MOADS 3 inventory emissions to determine the emissions in 1988 from platform equipment.

<u>THC & VOC:</u> The methodology used to develop THC and VOC emissions estimates from non-flare, combustion equipment for all years is based on the scaling and apportionment methodology used for NO_x emissions. THC emissions from natural gas engines represent an even larger fraction of the emissions from non-flare, combustion equipment on platforms than CO or NO_x: 97% or THC non-flare, combustion emissions are from natural gas engines. Just like NO_x emissions, the THC emissions from these equipments are scaled historically according to reported quantity of natural gas used. We calculated VOC emissions from THC emissions based on the ratio of VOC to THC emission factors.

Particulate Matter

The fine PM component from combustion sources are essentially all of the estimated PM. As such, PM_{10} and $PM_{2.5}$ are considered to be the same as PM emissions, except for construction and drilling related emissions where different emission factors were available. In contrast to other emission types (NO_x, and CO), PM emissions from natural gas engines do not represent a majority of the non-flare, combustion sources. To account for other combustion related PM emissions, the PM component of the inventory is calculated and apportioned differently than NO_x, CO, THC, and VOC emissions. PM emissions are calculated separately for natural gas engines, natural gas turbines, diesel fuel combustion (engines and turbines), and boilers. The MOADS 3 equipment classifications that are grouped into the following categories for PM emissions estimation purposes are included in Table A-3. The total estimated PM emissions from the following categories are apportioned to leases based on either natural gas production or oil production (as the emissions are fuel dependent) and then apportioned to platforms based on the number of active platforms in each lease. The yearly emissions are evenly distributed among all months.

<u>PM/PM_{10}/$PM_{2.5}$: natural gas engines (NGE)</u> The PM emissions from natural gas engine combustion are scaled and apportioned based on the ratio of MOADS 3 original PM emission factors to revised PM emission factors (as was done for other pollutants). The ratio of emission factors used here account for the distribution of engine types observed in the BOADS 2000 inventory and the newly updated emission factors. The PM emissions from natural gas engine are isolated from other equipment PM emissions to generate emissions exclusive to natural gas engine activity. The adjusted emissions are then scaled historically based on the variation in natural gas use, as reported by OGOR-B. As these engines are fueled by natural gas, the emissions are allocated to leases based on lease natural gas production.

$$\text{PM\_Emis} = \text{PM10 \_Emis} = \text{PM2.5\_Emis} = \text{Original PM\_NGE Emis} \times 0.3097 \text{ (Ratio)}$$

<u>PM/PM_{10}/$PM_{2.5}$:natural gas Turbines (NGT)</u> The only modification required to estimate PM emissions from natural gas Turbines is an adjustment of MOADS 3 emissions estimates for recent AP-42 emission factor update. The new AP-42 emission factor for PM is 7 lbs/MMscf, as compared to the emission factor used in MOADS 3, 35 lbs/MMscf. Once the 1990 base year emissions were established, then the historical emissions were estimated by scaling the emissions

by the ratio of natural gas used, as reported by OGOR-B. This methodology of scaling the emissions based on reported natural gas use is the same as for NO_x emissions for non-flare, combustion sources, above. As the fuel for this category is natural gas, the emissions are allocated among leases based on lease natural gas production.

$$\text{Adjusted PM\_NGT Emis}_{MOADS} = \text{PM\_NGT Emis(Original MOADS 3)} \times 7 \div 35$$

$$\text{Emis(yr)} = \text{PM\_NGT Emis}_{MOADS} \times \text{NGused(yr)} \div \text{NGused}_{MOADS}$$

<u>PM/PM10/PM2.5:Diesel combustion sources (DIE)</u> The emission factors for diesel engine combustion have not been changed since the application of emission factors in MOADS 3. The MOADS 3 PM emissions estimates for diesel engines were historically scaled according to yearly total oil production. We allocated emissions among leases based on reported levels of lease oil production.

$$\text{PM\_DIE Emis(yr)} = \text{PM\_DIE Emis}_{MOADS} \times \text{Oil production(yr)} \div \text{Oil production}_{MOADS}$$

<u>PM/PM10/PM2.5:Boilers (BOI)</u> – The only modification required to estimate PM emissions from Boilers is an adjustment of MOADS 3 emissions estimates for recent AP-42 emission factor update. The new AP-42 emission factor for PM is 7.6 lbs/MMscf, as compared to the fuel weighted emission factor used in MOADS 3, 6.17 lbs/MMscf. The historical emissions were estimated by scaling the boiler PM emissions by the ratio of natural gas used, as reported by OGOR-B. This methodology of scaling the emissions based on reported natural gas use is the same as for NOx emissions for non-flare, combustion sources, above. As the fuel for this category is natural gas, the emissions are allocated among leases based on lease natural gas production.

$$\text{Adjusted PM\_BOI Emis}_{MOADS} = \text{PM\_BOI Emis(Original MOADS 3)} \times 7.6 \div 6.17$$

$$\text{PM\_BOI Emis(yr)} = \text{PM\_BOI Emis}_{MOADS} \times \text{NGused(yr)} \div \text{NGused}_{MOADS}$$

Sulfur Oxides

Approximately 90% of SO_x emissions from engines, turbines and boilers are generated from diesel combustion. However, the SO_x emissions from all engine types contribute only 2 to 8% of the total SO_x inventory, depending on the year and flaring estimation methodology. Since the change in diesel use on platforms over the last 25 years is undocumented, the MOADS 3 SO_x emissions from engine combustion are held constant over all years. The SO_x emissions in the MOADS 3 inventory did not require adjustment as did NO_x, CO, VOC and THC because SO_x emissions are fuel dependant, rather than equipment dependant. As such, SO_x emissions are independent of NGE distribution and emission factor changes. The ratio of total equipment SO_x emissions to total equipment NO_x emissions for a given year is used to allocate yearly emissions to leases. The calculated SO_x to NO_x ratio is multiplied by each leases' NO_x emissions to generate lease specific SO_x emissions from non-flare, combustion equipment. Different ratios are used for each inventory year.

$$\text{Ratio 1977} = SO_x\text{\_EQ emissions (constant)} \div NO_x\text{\_EQ emissions (1977)}$$

$$= 363{,}892 \div 146{,}428{,}852 = 0.00248511$$

Ratio 1988 = 0.00121131

Glycol Dehydrator Units

As glycol unit operation is dependent upon the amount of natural gas processed, the emissions estimates from glycol equipment are based on natural gas production. Natural gas production information is used to determine both total yearly emissions from glycol units and to distribute emissions among leases. BOADS inventory data for natural gas processing rates were analyzed for statistically significant monthly variation in glycol operation; however, no significant variation was observed. As such, yearly emissions from glycol activities were distributed evenly among all months of the year.

Total Hydrocarbons and Volatile Organic Compounds

The emissions from Glycol Units were not incorporated into the original MOADS 3 inventory, so an entirely separate methodology was used to determine THC and VOC emissions from glycol activity. In an analysis of the BOADS inventory, it was found that the amount of natural gas processed by glycol dehydrator units constituted almost 100% of reported gas produced. Based on this, the THC and VOC emissions were estimated by multiplying natural gas production (being equal to natural gas processed by glycol units) by glycol unit emission factors, as shown below.

$$\text{Glycol\_Emis (VOC)} = 6.6 \text{ lbsVOC/MMscf} \times \text{NG Production (Mcf)} \div 1000$$

To derive the total hydrocarbon emissions: the relative concentrations of methane, ethane, and VOC were used. The composition of methane and ethane relative to VOC was determined from BOADS survey results. A ratio of methane to VOC concentrations and ethane to VOC was used to scale the VOC emissions and then adjust the emission factor for the glycol affinity to these compounds. The glycol affinities are based on the most commonly used type of glycol: Triethylene Glycol.

$$\text{Glycol\_Emis}_x = \text{Glycol\_Emis}_{VOC} \times \text{Concentration}_X / \text{Concentration}_{VOC} \times \text{Molecular Weight}_X/\text{Molecular Weight}_{VOC} \div \text{Glycol Affinity for X}$$

$$\text{Glycol\_Emis}_{CH4} = \text{Glycol\_Emis}_{VOC} \times (91.0/\ 6.2 \times 16/90) \div 400$$

$$\text{Glycol\_Emis}_{ethane} = \text{Glycol\_Emis}_{VOC} \times (2.8/\ 6.2 \times 30/90) \div 100$$

$$\text{Glycol\_Emis}_{THC} = \text{Glycol\_Emis}_{VOC} + \text{Glycol\_EmisCH4} + \text{Glycol\_Emis}_{ethane}$$

Natural Gas Release: Venting and Flaring

Overall Methodology:

The OGOR-B reports provide information about the total amount of gas sent to flares and vents in a given month; however, the amount sent to vents versus flares cannot be distinguished from the available data. The apportionment of gas sent to vents or flares is important for the determination of emissions. As no information was available to determine the relative amount of each activity, outside references were consulted. Brian Shannon, a member of the OOC, recommended a methodology to estimate the relationship between venting and flaring based on results of a recent inventory and his personal experience within the oil and gas industry. The BOADS inventory reported amount of gas vented and flared, individually. Brian Shannon has a high-level of confidence in the BOADS emission inventory because of considerable training that was performed prior to the inventory and the companies' use of consultants to prepare input data. Brian Shannon also confirmed our opinion that the trend since 1977 is toward venting rather than flaring. Brian Shannon's rationale is: "During the 1980's the MMS had an increased emphasis on conservation of resources, limited the both number of long-term well tests and the flaring of gas associated with oil production. Flaring today is generally only used on high flow-rate releases of natural gas. Normal production equipment blow down and upset releases are sent to the platform vent." Another concern is that the use of the word "flare" was misinterpreted in the MOADS inventory. Based on these considerations, the BOADS data were used as the basis for the estimation of current year venting and flaring practices, from which a trend is applied to estimate past venting and flaring.

The following methodology is used to backcast the calculated ratio of gas flared to gas vented from BOADS inventory data. Brian Shannon suggested increasing the ratio of flared to vented gas historically by 50% to 75% in 1977. This percentage increase is based on an assumed linear rate of change over time. The range of 50% to 75% is fairly arbitrary; however, with a lack of information, this is the best method available. Applying both ends of the range produces high flare/low vent and low flare/high vent estimates. The mid-points of these estimates were also calculated (see **Table A-13**). A Gulf Adjustment factor was applied to the low flare/high vent estimate to reflect the fact that in the 1991 inventory, platforms in the vicinity of the BNWA had a greater tendency to flare gas than did all platforms throughout the Gulf, taken as a whole. The Gulf Adjustment factor tends to lower the estimated ratio of flaring to venting; therefore, it was applied only to the lower end of the uncertainty range. In other words, it is treated as a factor that increases the level of uncertainty in the emissions estimates rather than a simple scaling factor. The equation developed to perform the estimated increase in flaring ratio for any given year is as follows:

$$\text{Ratio}_{hi} = (\text{Ratio}_{BOADS} \times [75 \div (2000 - 1977) \times (2000 - \text{year})] \div 100) + \text{Ratio}_{BOADS}$$

$$\text{Ratio}_{lo} = [(\text{Ratio}_{BOADS} \times [50 \div (2000 - 1977) \times (2000 - \text{year})] \div 100) + \text{Ratio}_{BOADS}] \times \text{Gulf\_Adjustment}$$

$$\text{Ratio}_{mid} = (\text{Ratio}_{hi} + \text{Ratio}_{lo}) \div 2$$

$$\text{Ratio}_{BOADS} = \text{Volume Flared}_{BOADS} \div \text{Volume Vented}_{BOADS}$$

$$\text{Gulf\_Adjustment} = (\text{Volume Flared}_{MOADS\ 3} \div \text{Volume Vented}_{MOADS\ 3}) \div (\text{Volume Flared}_{MOADS\ 3INBRETON} \div \text{Volume Vented}_{MOADS\ 3INBRETON}) = 0.713$$

Use the ratio estimated for the year of interest to determine the relative percent vented or flared. Multiply the percent vented or flared by the total amount released as reported by the OGOR-B reports, listed in Table A-2.

%Vented= 100 ÷ (1 + Ratio)

%Flared= 100 ÷ (1+ 1/Ratio)

The total gas released to either vents or flares was divided by yearly natural gas production to determine the annual percent released as a function of production. The percent released in 1977 was then extrapolated from the trend developed from data for 1985 through 2000. This trend estimated that 0.95% of all gas produced was released in 1977. To quality assure the validity of both the reported OGOR-B data and the developed trend, the percent of gas released as reported in OGOR-B was compared to the percent of gas released on a national level as reported by EIA. The data from the EIA was for the period from 1954 to 2000. The two trends developed from the separate datasets were similar, but the percentage released nationally was higher, in general, than that for offshore platforms. Despite this national trend being higher on average than Gulf specific data indicates, the results of extrapolating the national trend for the year 1977 produced a lower estimate of percent of gas released in 1977. The national trend estimated that 0.82% of natural gas production was released in 1977. Realistically, the percent of gas released in 1977 from offshore platforms was influenced both by offshore conditions (pipeline infrastructure) and national trends (i.e. natural gas price, lack of regulation, safety issues, etc.). It is likely that the percent of natural gas released in 1977 is a combination of factors underlying both trends. To generate an estimate of total natural gas released, the mid-point of the two trend lines was used to calculate total estimated natural gas released in 1977.

Table A-13. Estimates of volume of gas vented and flared by year.

Estimate by Year	Total Volume Released (Mcf)	Estimated Volume Flared (MCF)	Estimated Volume Vented (MCF)	Ratio of Volume Flared to Volume Vented
High Flare/Low Vent Estimate				
1977	33,814,584	15,988,535	17,826,050	0.897
1988	16,869,964	7,022,220	9,847,744	0.713
1991-92	11,924,751	4,825,220	7,099,531	0.680
2000	12,834,605	4,349,059	8,485,546	0.513
Mid Flare Estimate				
1977	33,814,584	14,183,523	19,631,061	0.723
1988	16,869,964	6,239,167	10,630,796	0.587
1991-92	11,924,751	4,291,638	7,633,114	0.562
2000	12,834,605	3,915,237	8,919,368	0.439
Low Flare/High Vent Estimate				
1977	33,814,584	11,971,788	21,842,796	0.548
1988	16,869,964	5,320,828	11,549,136	0.461
1991-92	11,924,751	3,671,332	8,253,419	0.445
2000	12,834,605	3,434,666	9,399,938	0.365

Emission factors for all pollutants were applied to the estimated quantity of gas vented and gas flared; this results in the total emissions by year from venting and flaring activities. The above methodology was used to replace the venting and flaring emissions estimate developed for the MOADS inventory. In comparing the MOADS 3 inventory and the results of this methodology, the total quantity of gas vented and flared does not vary substantially, but the proportion of gas vented versus flared does, as do emission factors for some pollutants: namely, SO_x and THC.

Nitrogen Oxides, Carbon Monoxide, Sulfur Oxides, and Particulate Matter

After the above methodology was used to generate estimated quantities of natural gas flared in each year, the amount of gas flared is multiplied by emission factors to generate total emissions from flaring. Emission factors used to estimate emissions for gas flared are listed in **Table A-14**. A natural gas heating value of 1050 Btu/scf is assumed. For the 1988 inventory, yearly total emissions are apportioned to leases by monthly OGOR-B reported gas vented and flared. For the 1977 inventory, when no OGOR-B data is available, the yearly emissions are apportioned to leases based on natural gas production and evenly distributed throughout the year. The lease emissions are allocated to platforms evenly among number of active platforms for each lease.

$VolFlared(yr) = \%Flared(yr) \div 100\% \times Total\_Released(yr)$

$NOx\ Emis\_Flared = VolFlared\ (Mcf) \div 1000 \times 1050\ Btu/scf \times 0.068\ lb\ NOx\ /MMBtu$

Table A-14. Emission factors for natural gas flares.

Emission Type	Emission factor (lb/MMBtu)
NO_x	0.068
CO	0.37
PM (equal to PM_{10} and $PM_{2.5}$)[a]	9.4×10^{-4}

[a] The emission factor for PM is derived from BOADS survey results and EPA AP-42 smoky flares.

SO_x emissions from flaring of natural gas depend on the amount of H_2S of the gas sent to the flare. It is assumed that all H_2S is converted to SO_x in the combustion process. For the purposes of SO_x emissions estimation, a hydrogen sulfide content of 4125 ppmv is assumed. This is the mid-point of the average range determined from BOADS survey results. It is important to note that this assumed sulfur content is much greater than the default value used in MOADS 3.

SO_x Emis(lb) = VolFlared(Mscf) $\times$ 1000 $\times$ H_2S Conc $\times$ 10-6 $\times$ 0.98 $\times$ 64 lb/lb.mol $\div$ 379.4 scf/lb.mol

Total Hydrocarbons and Volatile Organic Compounds

After the estimated quantities of natural gas vented in each year were generated, the amount of gas vented is multiplied by emission factors to generate total emissions from venting. Emission factors used to estimate emissions for gas vented are described below. A natural gas heating value of 1050 Btu/scf is assumed. For the 1988 inventory, yearly total emissions are apportioned to leases by monthly OGOR-B reported gas vented and flared. For the 1977 inventory, when no OGOR-B data is available, the yearly emissions are apportioned to leases based on natural gas production and evenly distributed throughout the year. The lease emissions are allocated evenly to platforms among number of active platforms for each lease.

The emission factors used to estimate emissions from venting activities differ from those used in MOADS 3 inventory in several ways. First of all, the MOADS 3 inventory only calculated the THC emissions from venting activities, and did not include an estimate of VOC emissions. Secondly, the MOADS 3 inventory assumed that the natural gas sent to vents was composed of 100% hydrocarbons. To determine the VOC portion of the natural gas stream several sources of information were consulted: BOADS survey results, a speciation profile for flashing losses, and a report of the composition of gulf natural gas. Based on the data reported from BOADS surveyed VOC content of gas sent to vents, there seemed to be two different natural gas speciation profiles. The BOADS inventory contained 90 vents with non-zero, non-null values for VOC content of the natural gas stream. Of these 90 vents, an average VOC concentration of around 30,000 ppmv was reported (with a standard deviation of around 30,000.

Vents in the BOADS database with high VOC concentrations (e.g., >200,000) are probably similar to the profile for flashing losses. Vents with low VOC concentrations (e.g., <50,000) are probably similar to the profile for GOM natural gas. As the low VOC concentration gas predominates the vent stream, the profile for Gulf-specific natural gas was used to estimate both THC and VOC emissions. It is important to note that due to the reported natural gas composition of the Gulf, not all the gas reportedly sent to vents is considered to be composed of hydrocarbons (as compared with the MOADS inventory assumption).

SAI (1995) shows that the composition of Gulf natural gas is

0.8% by weight non-hydrocarbons (or around 0.3% by volume = 3,000 ppmv)
90.5% by weight methane (or around 96% by volume = 960,000 ppmv)
3.5% by weight ethane (or around 1.7% by volume = 17,000 ppmv)
5.2% by weight VOCs (or around 2% by volume = 20,000 ppmv)
Conc Methane 960,000 ppmv; MWTme = 16 lb/lb.mol
Conc Ethane 17,000 ppmv; MWTet = 30 lb/lb.mol
Conc VOC 20,000 ppmv; MWTvoc = 47 lb/lb.mol

$$\text{Emis(lb)} = \text{VolVented(scf)} \times \text{Conc} \times 10^{-6} \div 379.4 \text{ scf/lb.mol} \times \text{MWT}$$

EF voc=2.4776 lbs/Mcf

THC_Emis = VOC_Emis + Me_Emis + Et_Emis

EF THC= 44.3068 lbs/Mcf (compare to MOADS 3 THC emission factor of 47 lbs/Mcf)

Storage Tanks

Total Hydrocarbons and Volatile Organic Compounds

The most accurate inventory to-date of storage tanks and their associated emissions for the Gulf of Mexico region is from the MOADS 3 inventory. To scale these emissions historically, the most appropriate activity surrogate is oil production. As more oil is produced, potentially there is more stored at any given time on platforms and, additionally, the working losses from transferring oil into and out of tanks will be increased. (1:1 relationship for emissions from working losses and production, breathing losses minor). Thus, to generate historical emissions estimates, the emissions from storage tanks are scaled according to the change in oil production. The historical storage tank emissions are then apportioned to leases based on oil production and these emissions are apportioned evenly year round. The potential emissions variation from seasonal changes was found to be insignificant based on Gulf-specific meteorological data and emissions estimation software.

The emissions from MOADS 3 inventory from both crude oil tanks and diesel storage tanks are estimated only for THC. The MOADS 3 emissions for storage tanks are scaled linearly according to oil production. The VOC emissions are estimated by multiplying the ratio of VOC and THC emissions to the estimated historical THC emissions. As discussed previously, a speciation profile for flashing loses is available to estimate the portion VOC in THC emissions. The profile for flashing losses is particularly applicable to the estimation of VOC emissions from storage tanks as the volatile component of emissions is likely to be much higher than that typically found in natural gas or oil. The calculation of VOC component of THC emissions is below.

$$VOC\_Emis = THC\_Emis \times 92.84 \div 100$$

Spatial and Temporal Allocation

Estimated annual emissions from platform specific equipment, including engines, gas processing equipment, and storage tanks, were first spatially allocated based on lease specific data. Lease emissions were then distributed spatially to platform sources based on the platform list provided by MMS. The lease emissions were distributed evenly to the number of active platforms within a lease in each year. For example, if there were three active platforms within a lease in 1977, a third of the total emissions for the lease were apportioned evenly to each of those three platforms. If the MMS records did not indicate that a lease had any active platforms within a given year, then all of the lease's emissions were allocated to the closest platform as determined with ArcView GIS analysis tools. Emissions were distributed temporally in different ways, depending upon the type of activity data available.

APPENDIX B

GRIDDED EMISSIONS FOR MOBILE SOURCES, 1977 AND 1988

MOBILE SOURCE EMISSION GRID

Grid was defined as follows:

Grid dimension was 45 x 26,
total number of cells 1170, counting from left to right from SW corner, last cell (1170) is NE corner
SW corner at 97.2 E, 25.616 N
NE corner at 87.81 E, 30.694 N

MAP PROJECTION

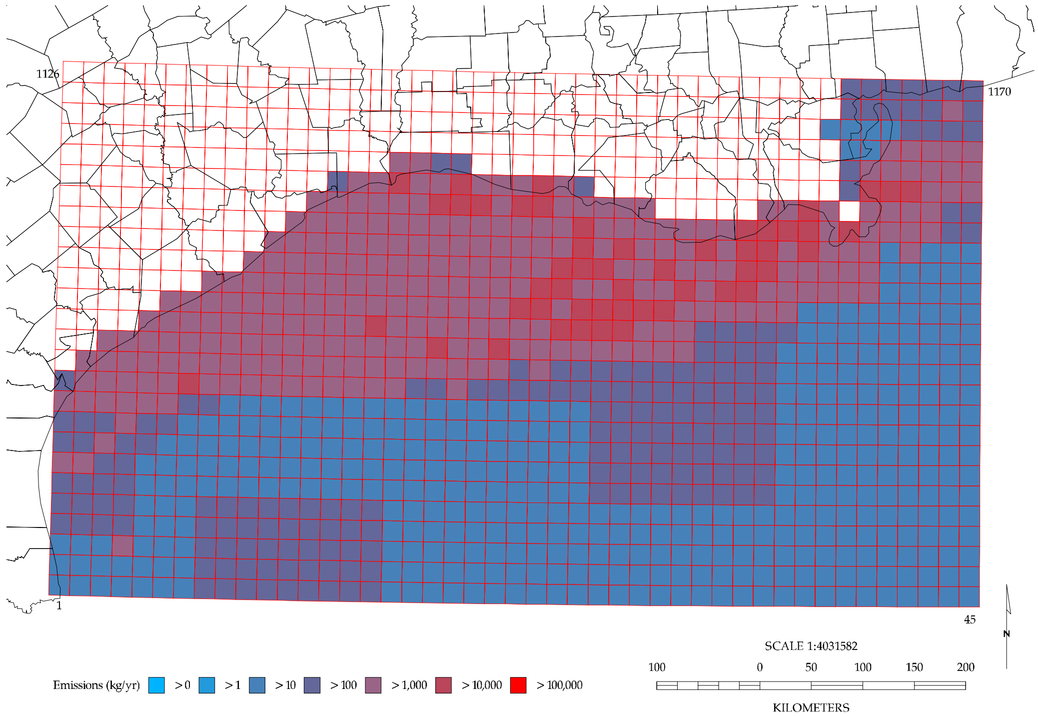
Map projected used was ALBERS, parameters as follows:

Zunits	NO
Units	METERS
Spheroid	CLARKE1866
Xshift	0.0000000000
Yshift	0.0000000000

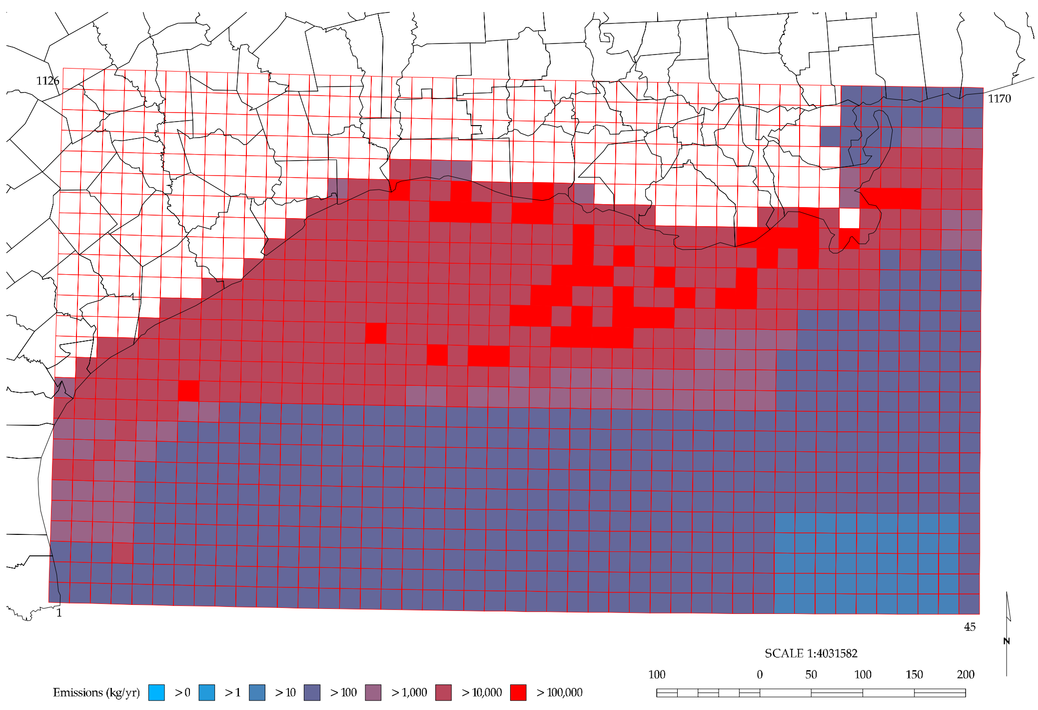
Parameters

29 30 0.000 /* 1st standard parallel
45 30 0.000 /* 2nd standard parallel
-96 0 0.000 /* central meridian
23 0 0.000 /* latitude of projection's origin
0.00000 /* false easting (meters)
0.00000 /* false northing (meters)

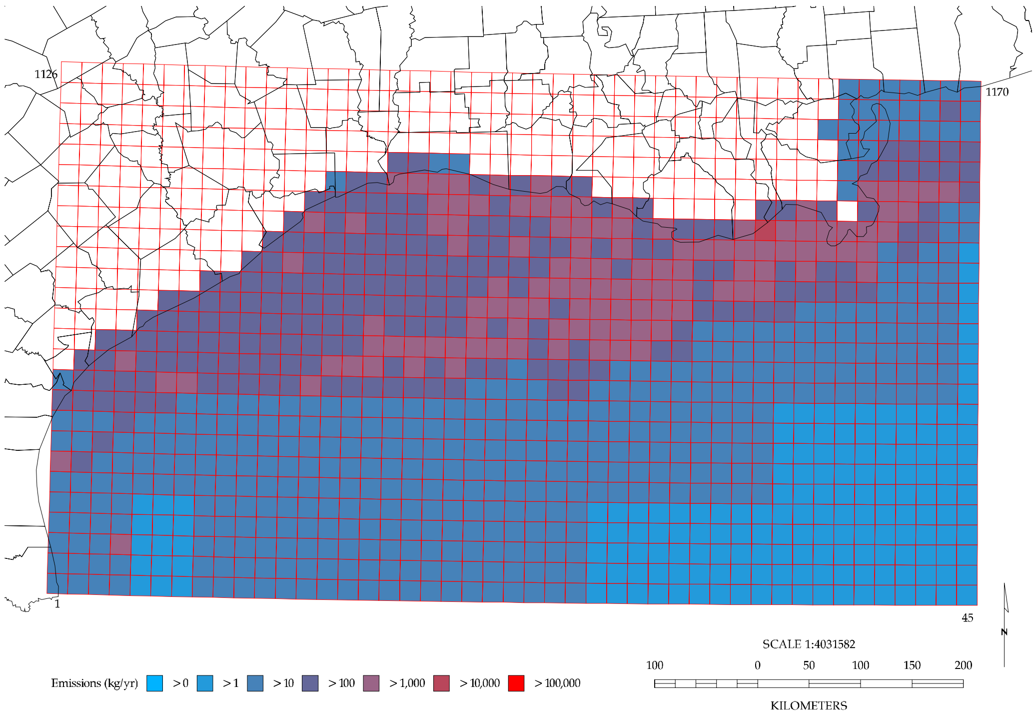
1977 Gulf of Mexico Estimated Mobile Source Emissions
All Sources CO Emissions



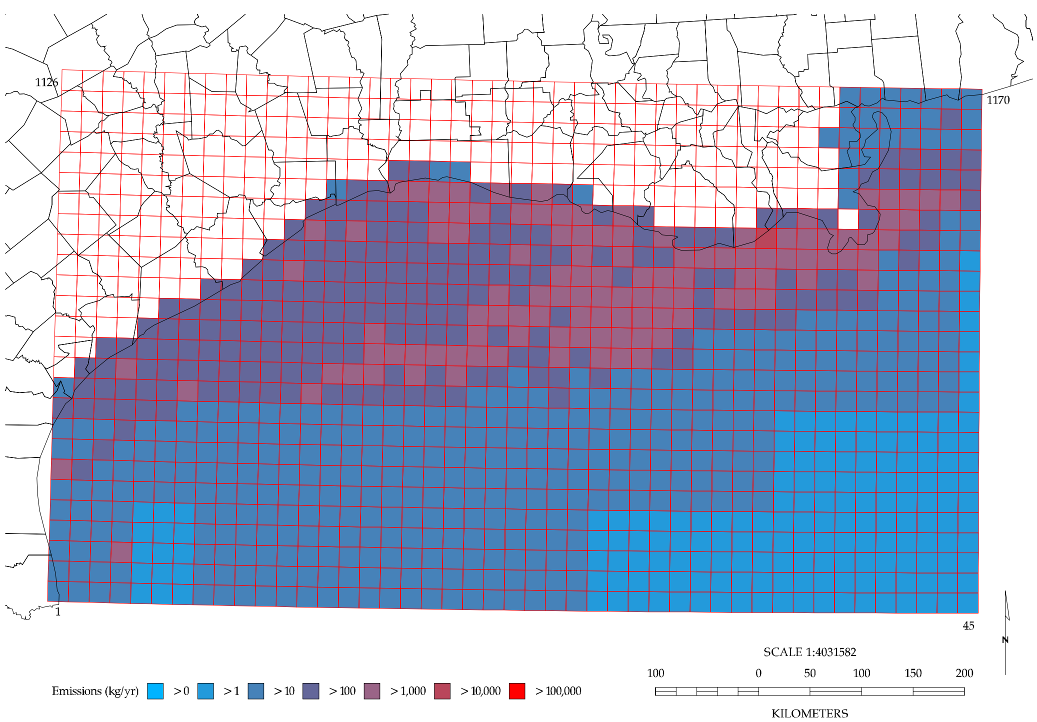
1977 Gulf of Mexico Estimated Mobile Source Emissions
All Sources NOx Emissions



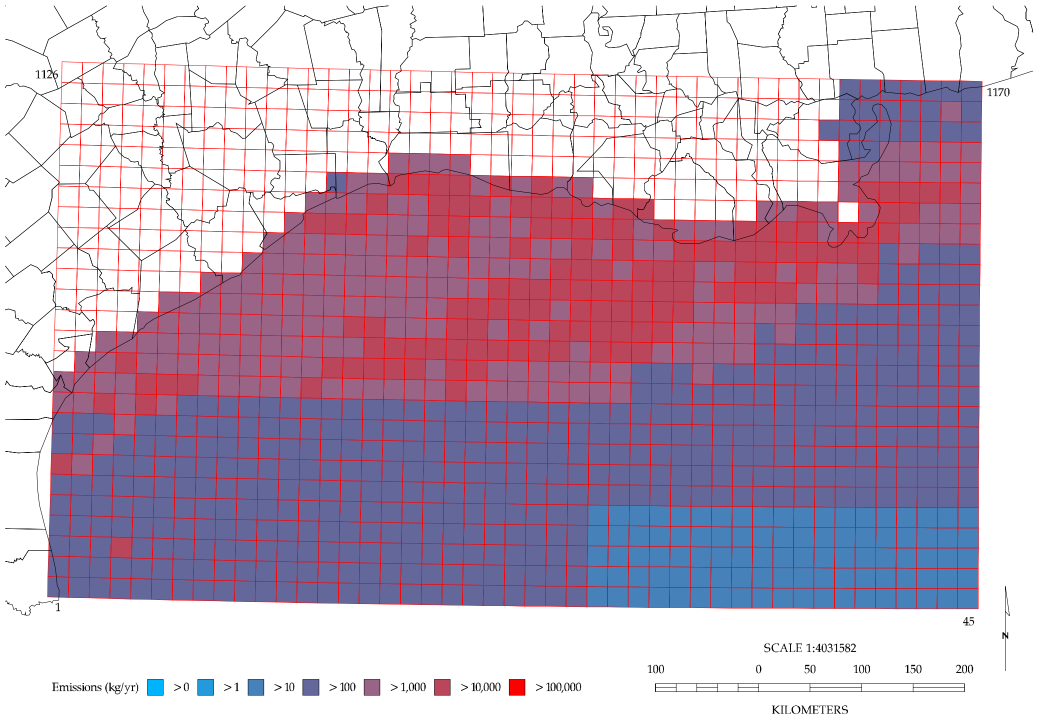
1977 Gulf of Mexico Estimated Mobile Source Emissions
All Sources PM10 Emissions



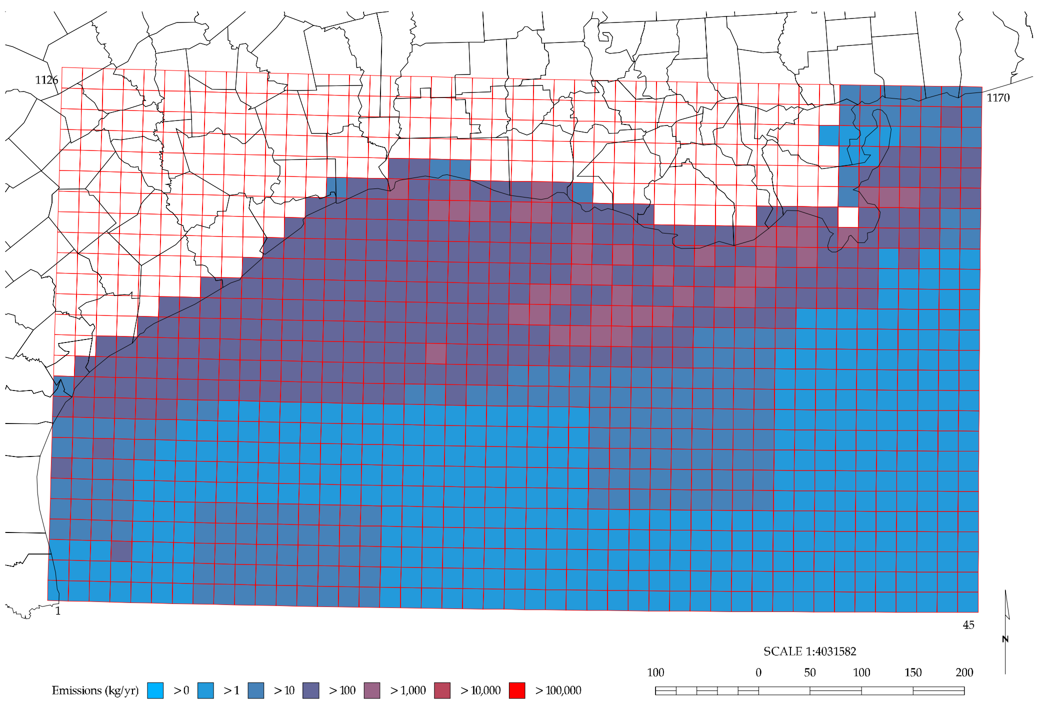
1977 Gulf of Mexico Estimated Mobile Source Emissions
All Sources PM2.5 Emissions



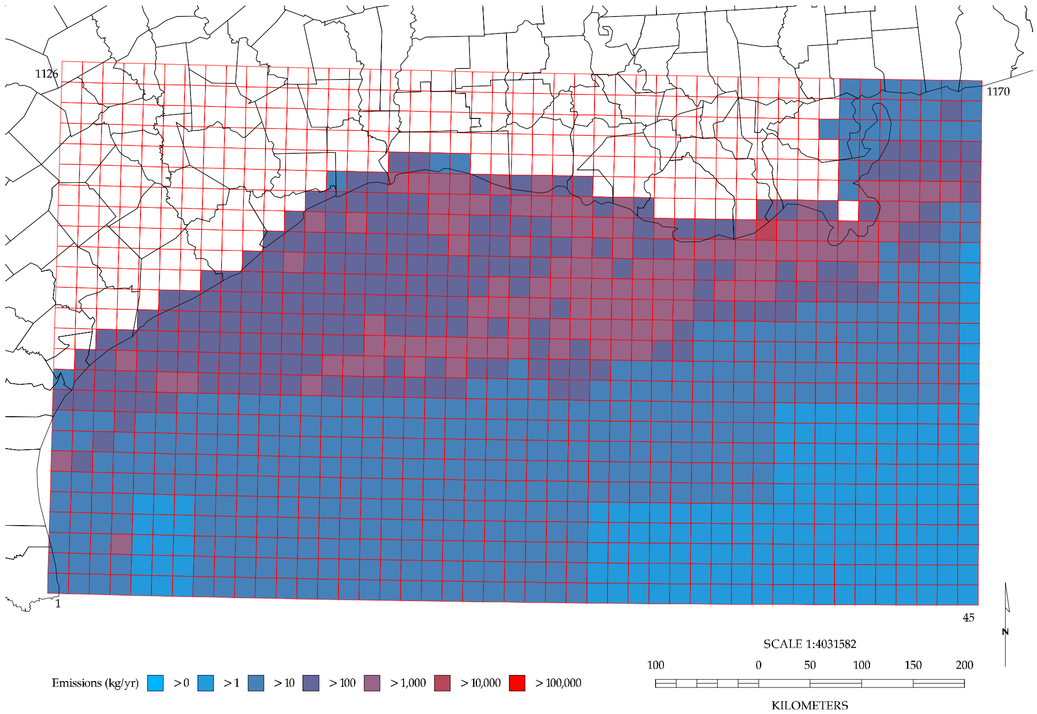
1977 Gulf of Mexico Estimated Mobile Source Emissions
All Sources SOx Emissions



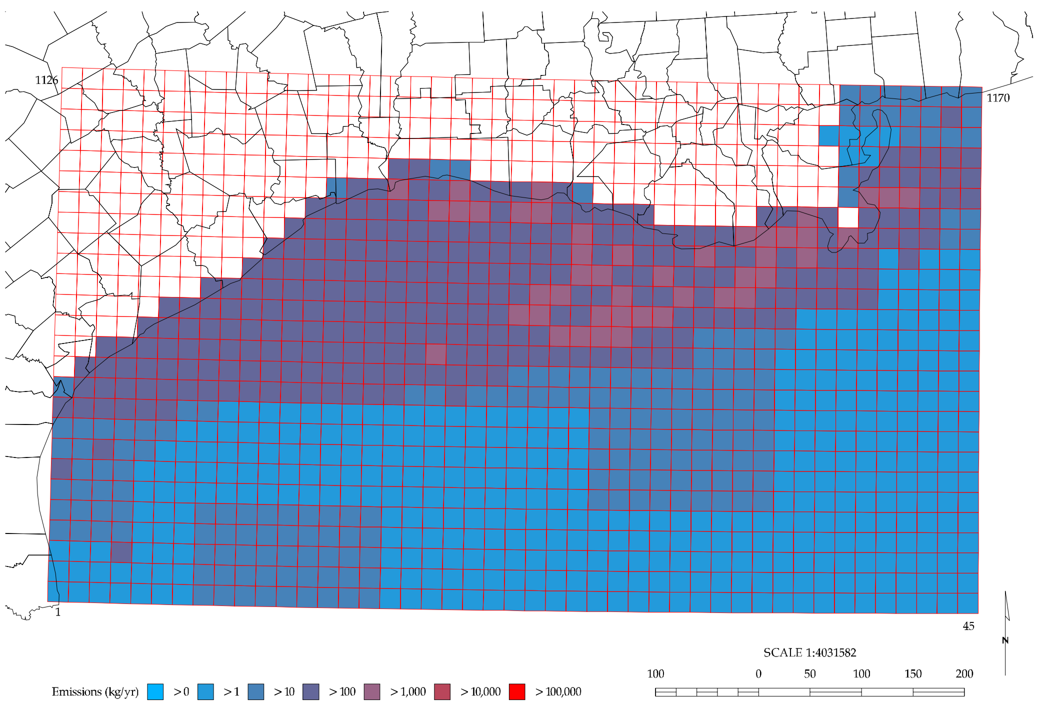
1977 Gulf of Mexico Estimated Mobile Source Emissions
All Sources THC Emissions



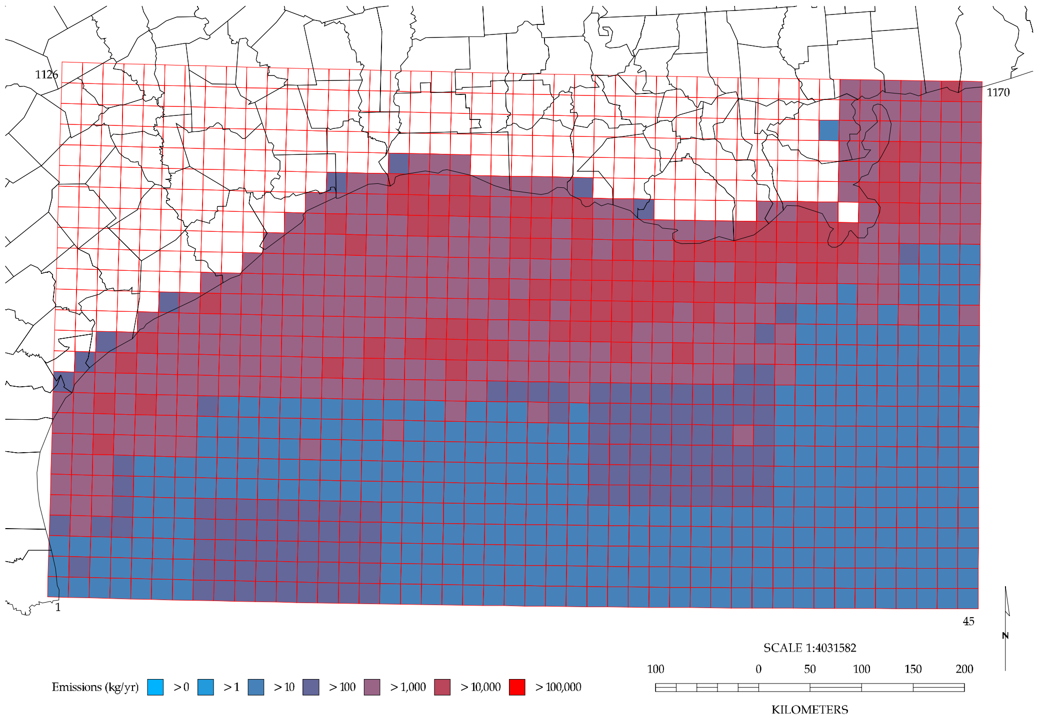
1977 Gulf of Mexico Estimated Mobile Source Emissions
All Sources TSP Emissions



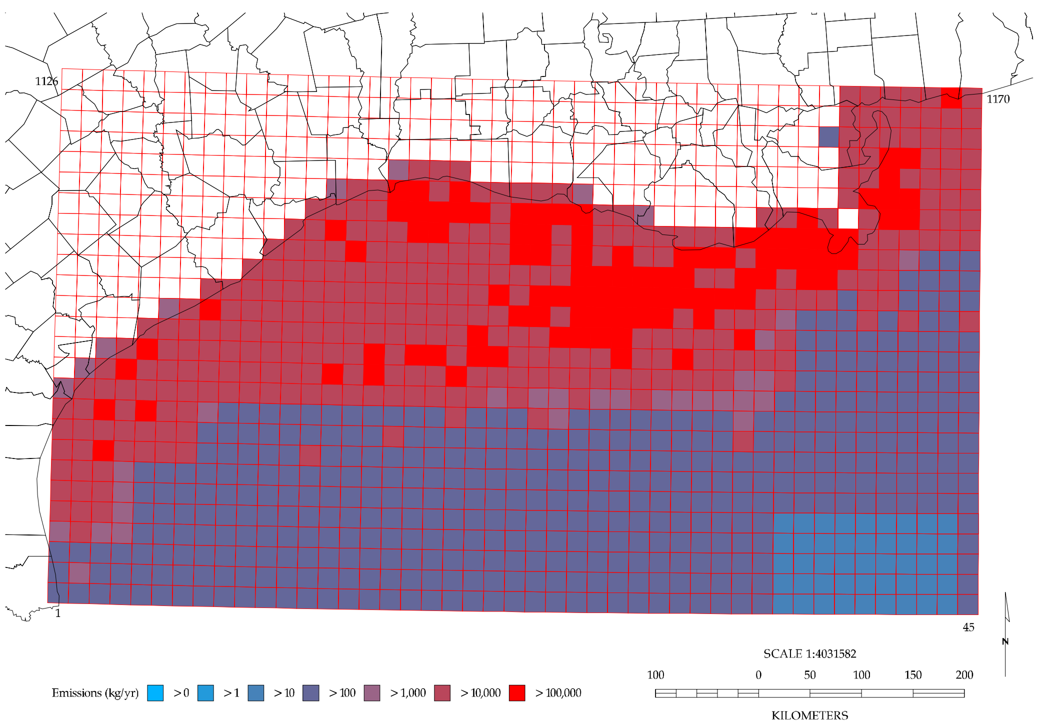
1977 Gulf of Mexico Estimated Mobile Source Emissions
All Sources VOC Emissions



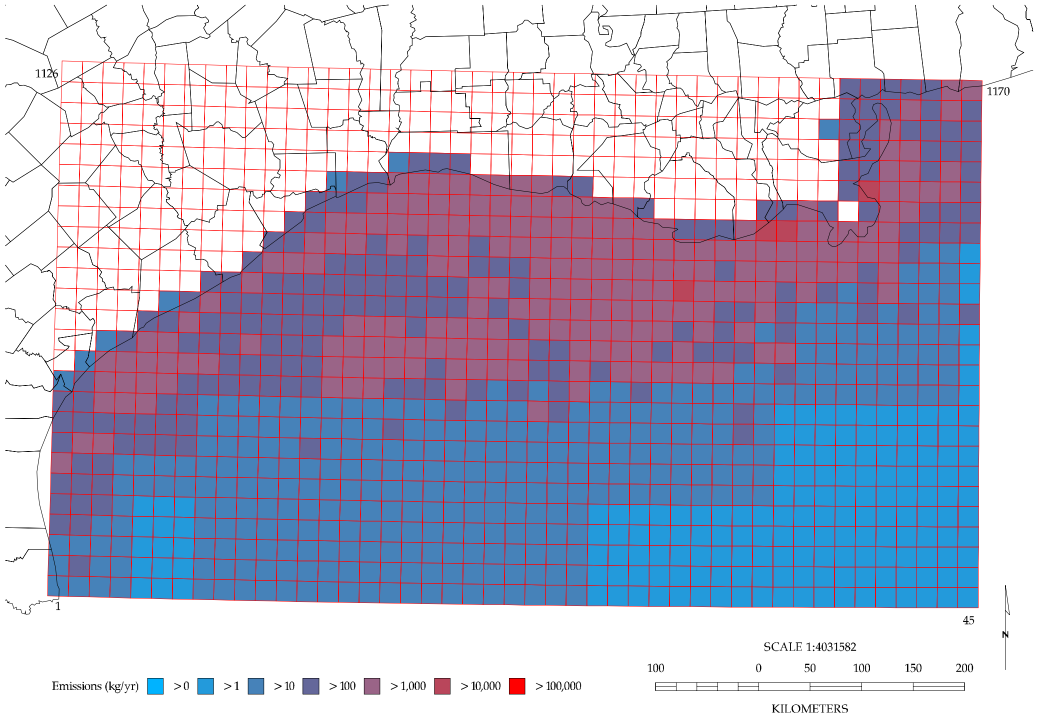
1988 Gulf of Mexico Estimated Mobile Source Emissions
All Sources CO Emissions



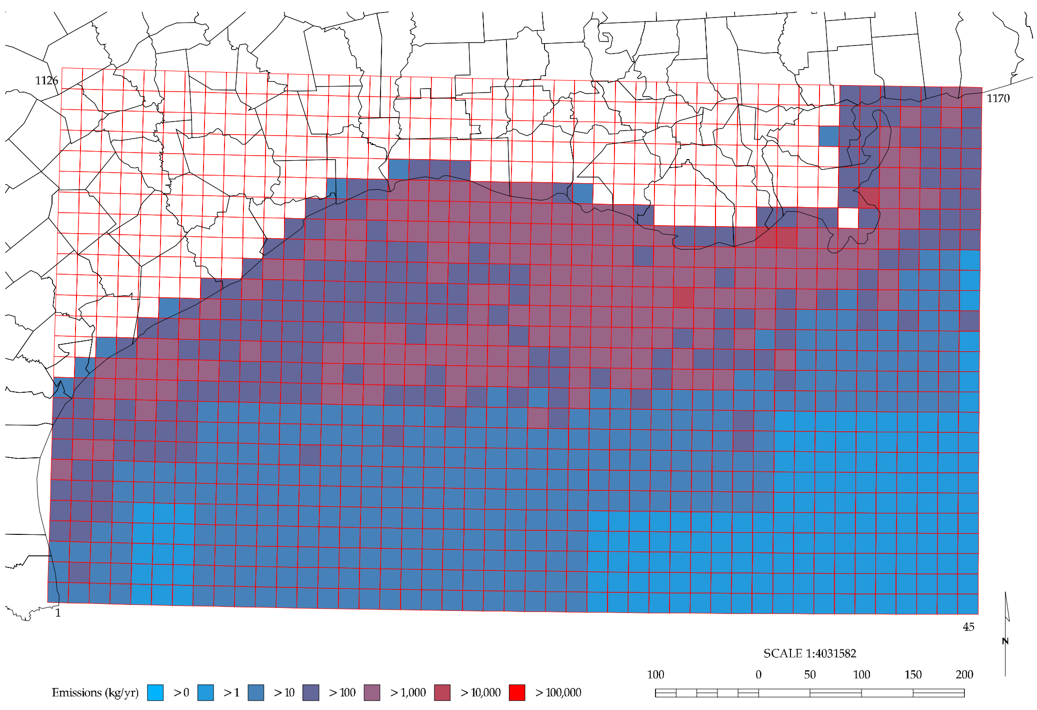
1988 Gulf of Mexico Estimated Mobile Source Emissions
All Sources NOx Emissions



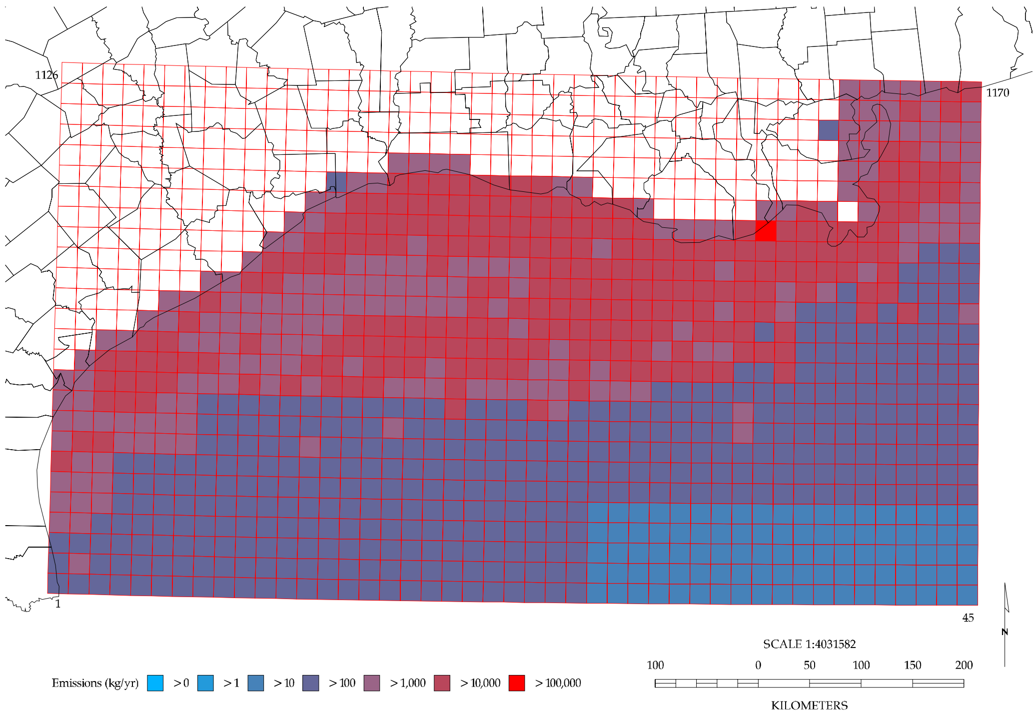
1988 Gulf of Mexico Estimated Mobile Source Emissions
All Sources PM10 Emissions



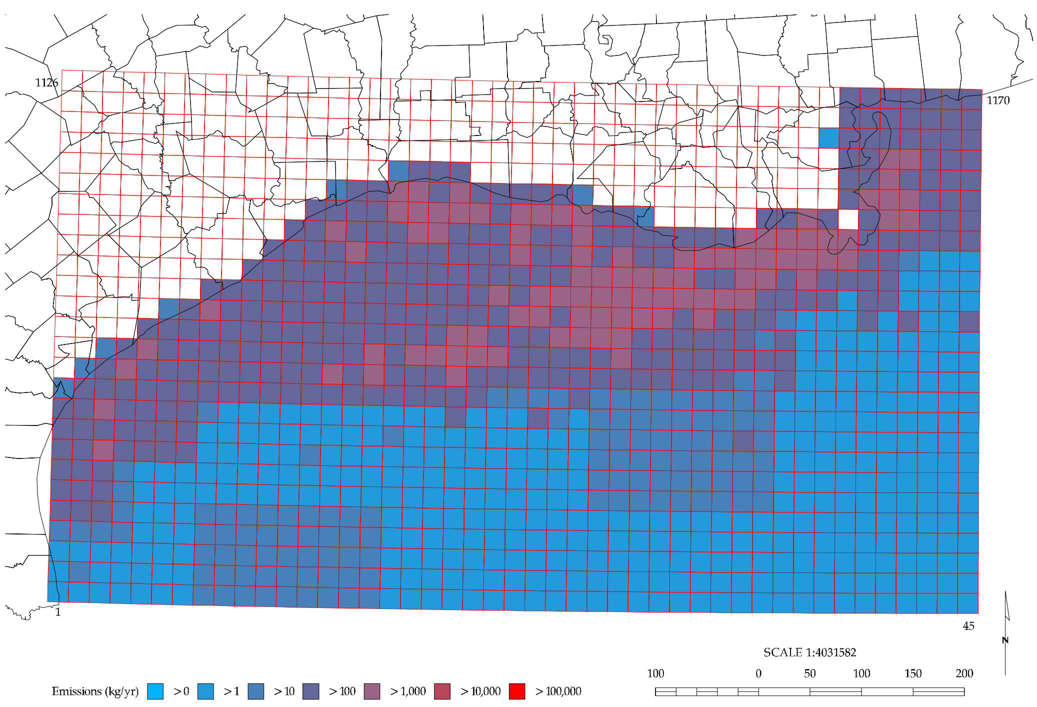
1988 Gulf of Mexico Estimated Mobile Source Emissions
All Sources PM2.5 Emissions



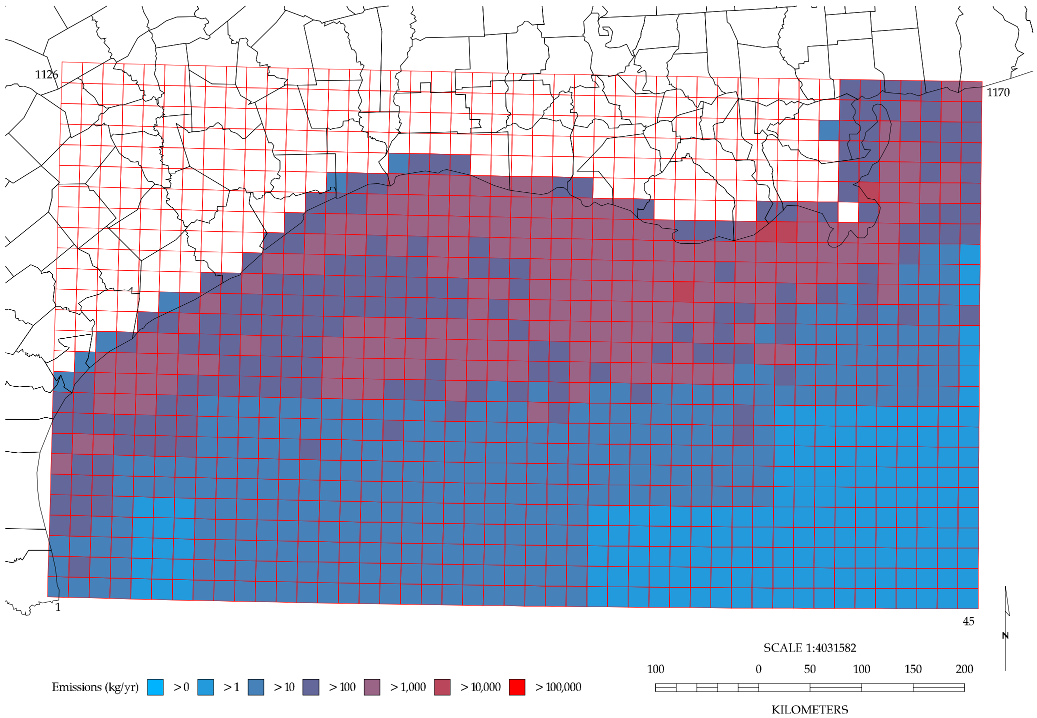
1988 Gulf of Mexico Estimated Mobile Source Emissions
All Sources SOx Emissions



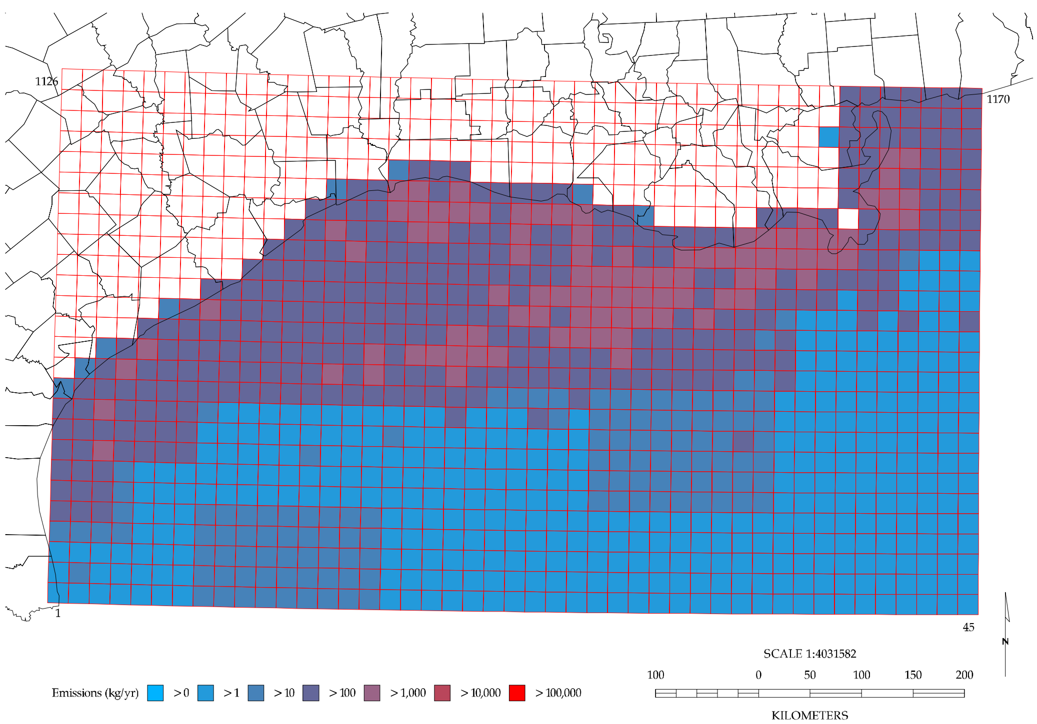
1988 Gulf of Mexico Estimated Mobile Source Emissions
All Sources THC Emissions



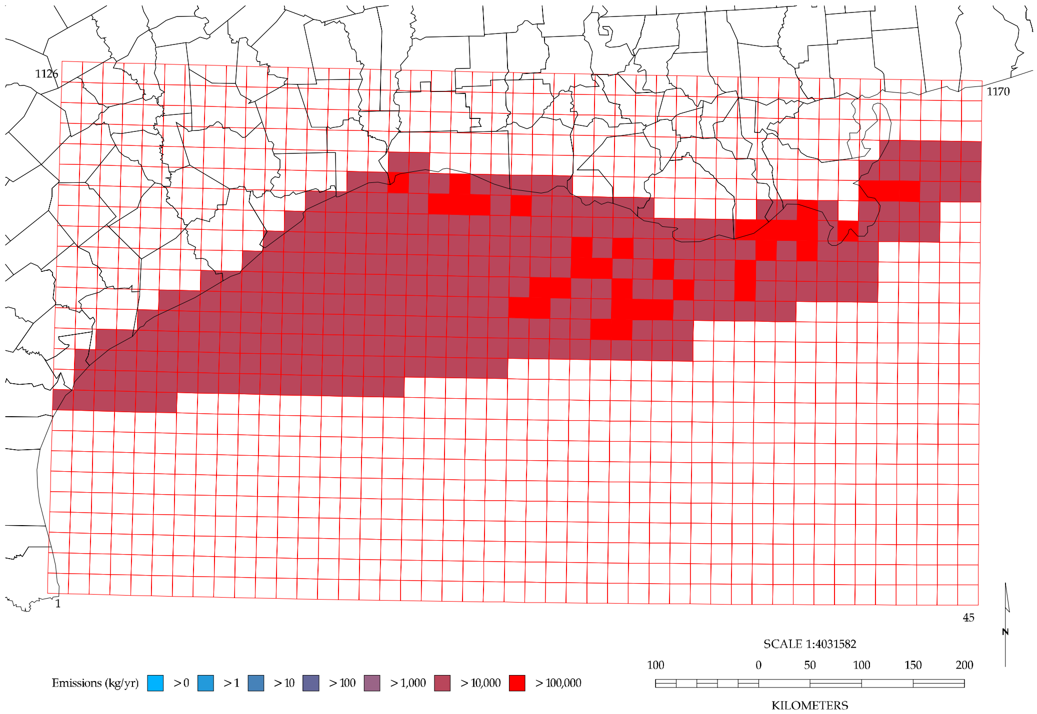
1988 Gulf of Mexico Estimated Mobile Source Emissions
All Sources TSP Emissions



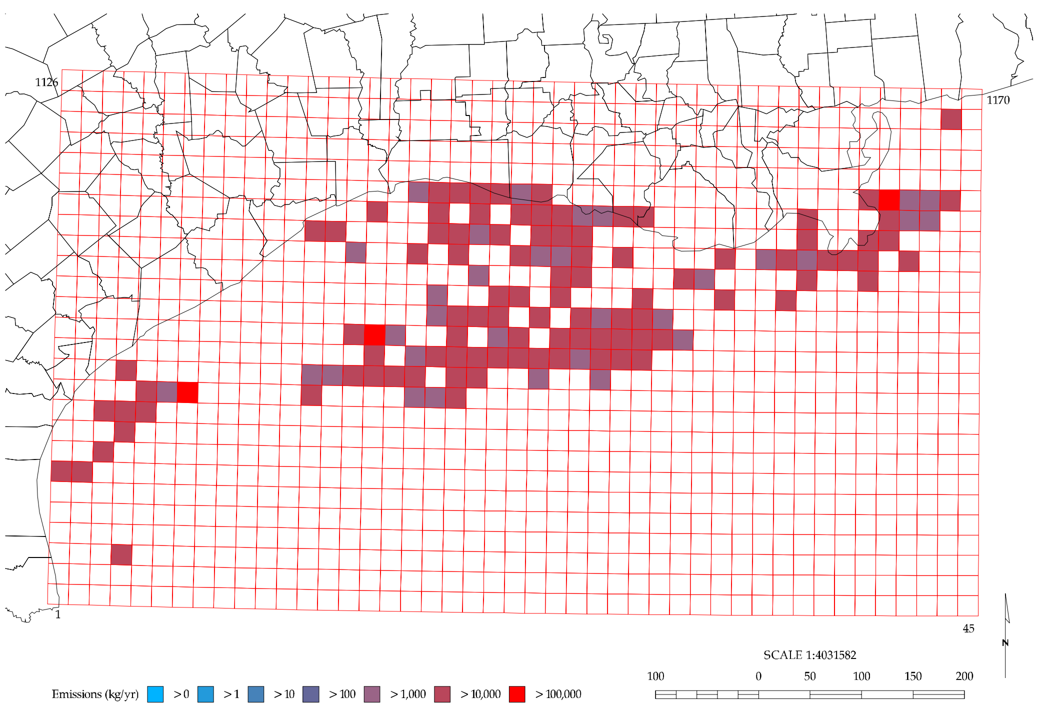
1988 Gulf of Mexico Estimated Mobile Source Emissions
All Sources VOC Emissions



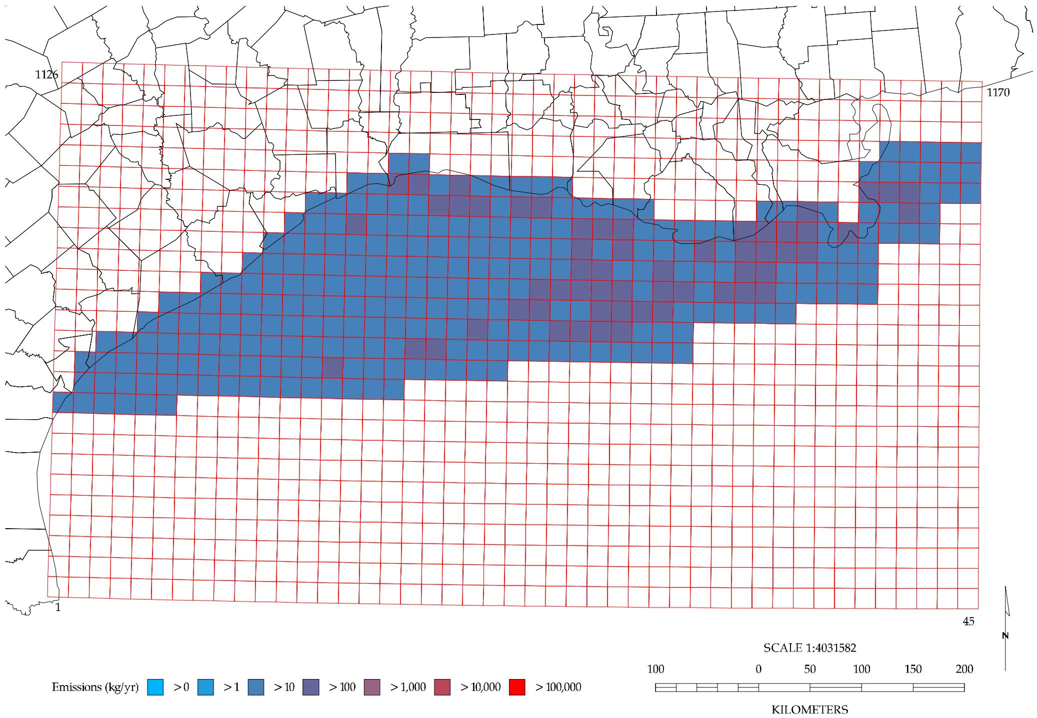
1977 Gulf of Mexico Estimated Mobile Source Emissions
Crew & Supply Boats NOx Emissions



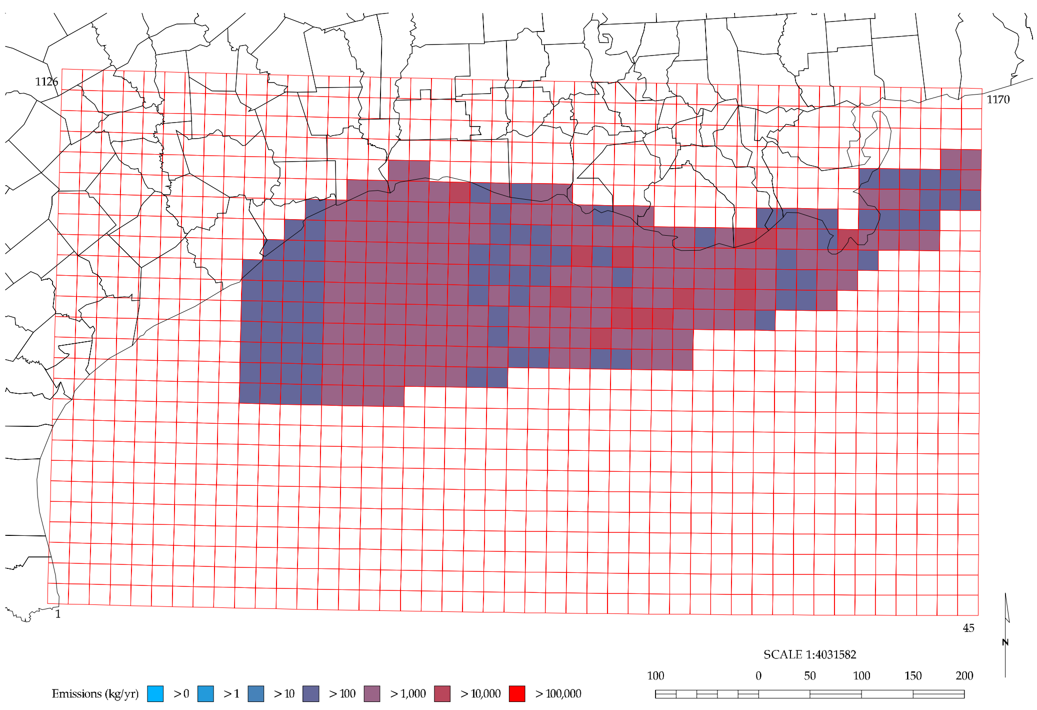
1977 Gulf of Mexico Estimated Mobile Source Emissions
Drill Ships NOx Emissions



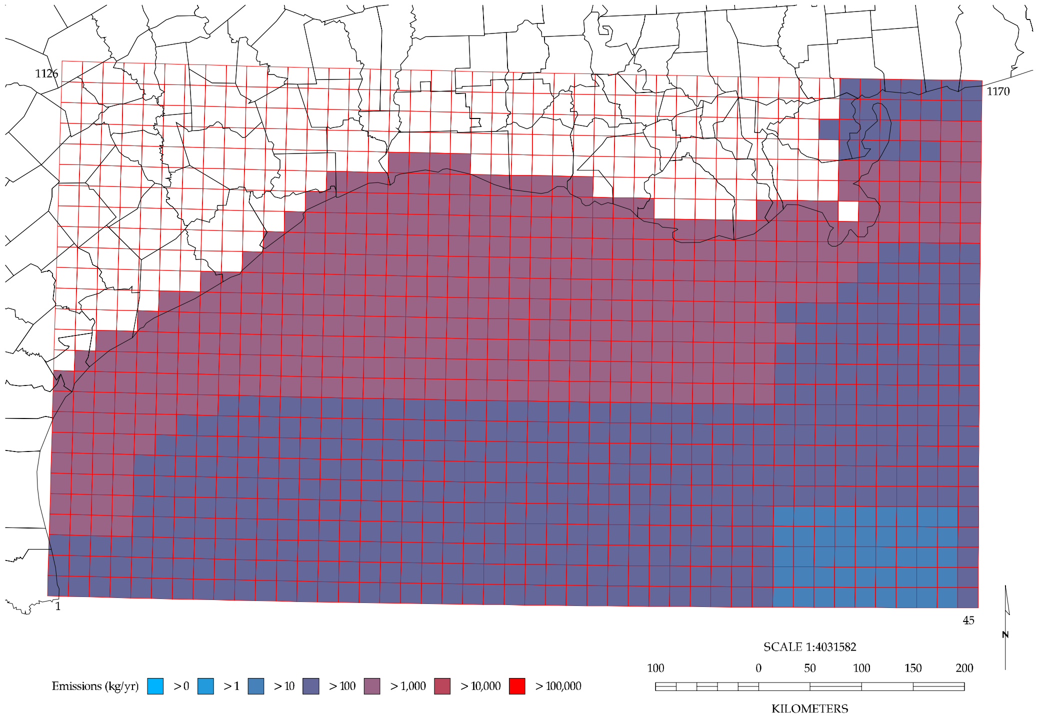
1977 Gulf of Mexico Estimated Mobile Source Emissions
Crew & Supply Helicopters NOx Emissions



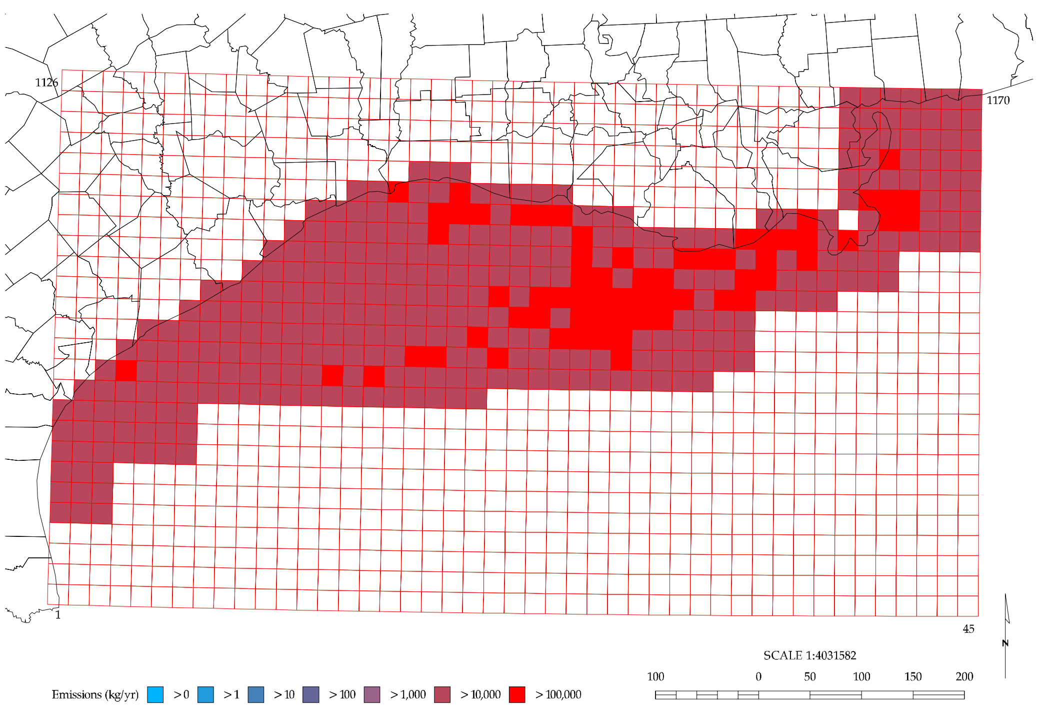
1977 Gulf of Mexico Estimated Mobile Source Emissions
Pipe-Laying Ships NOx Emissions



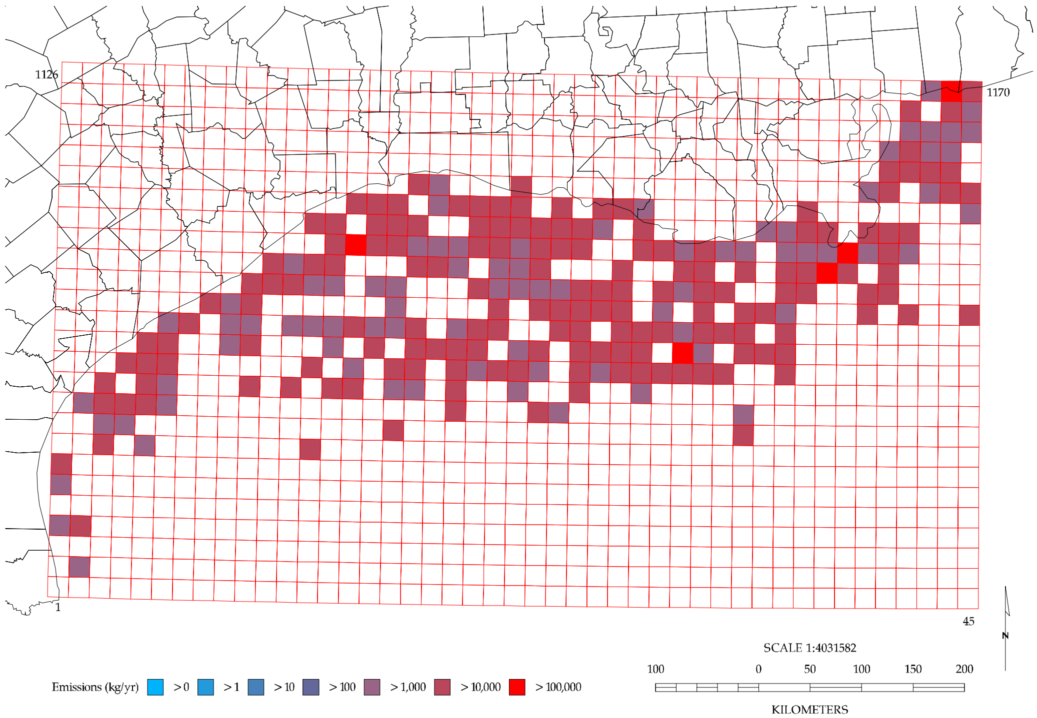
Gulf of Mexico Estimated Mobile Source Emissions
Exploration Vessels NOx Emissions



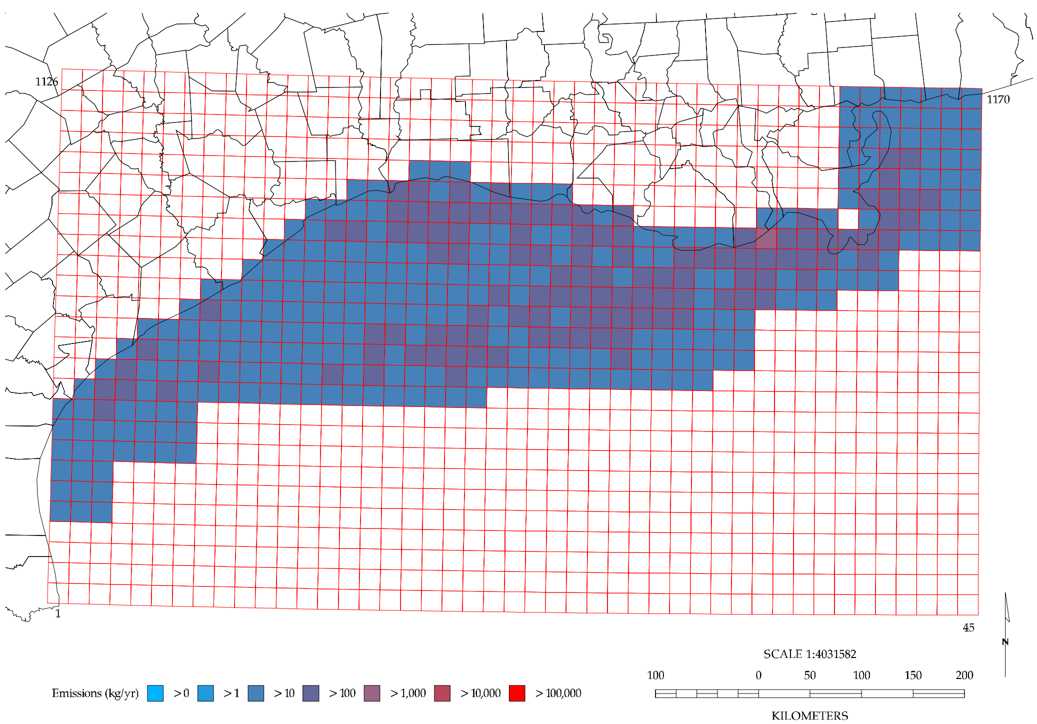
1988 Gulf of Mexico Estimated Mobile Source Emissions
Crew & Supply Boats NOx Emissions



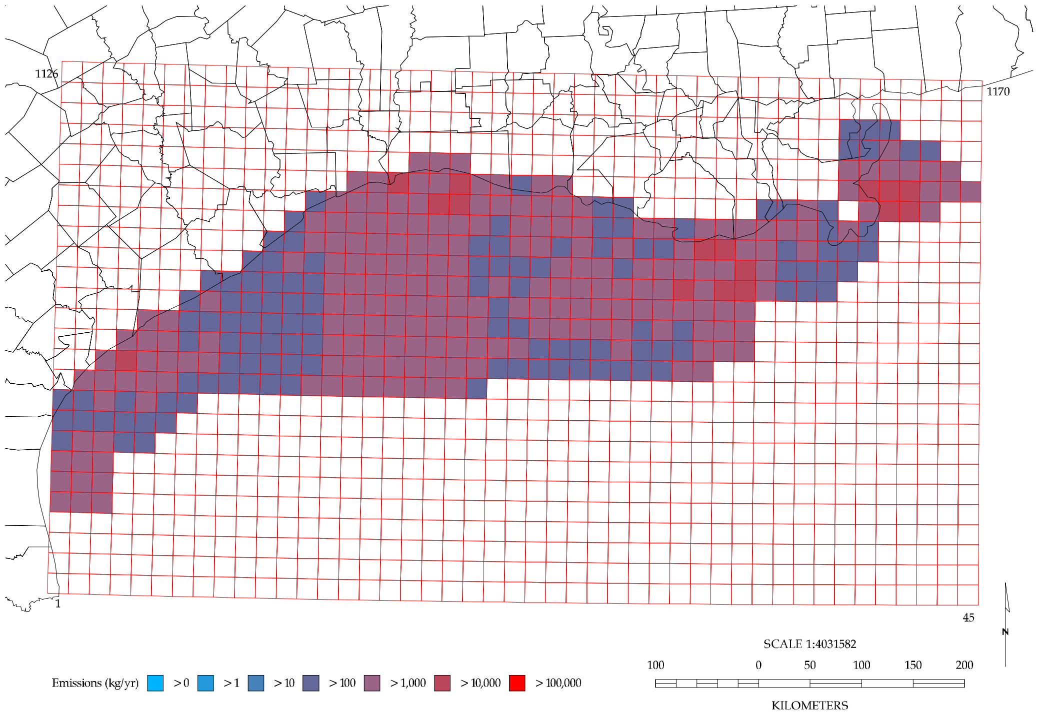
1988 Gulf of Mexico Estimated Mobile Source Emissions
Drill Ships NOx Emissions



1988 Gulf of Mexico Estimated Mobile Source Emissions
Crew & Supply Helicopters NOx Emissions



1988 Gulf of Mexico Estimated Mobile Source Emissions
Pipe-Laying Ships NOx Emissions

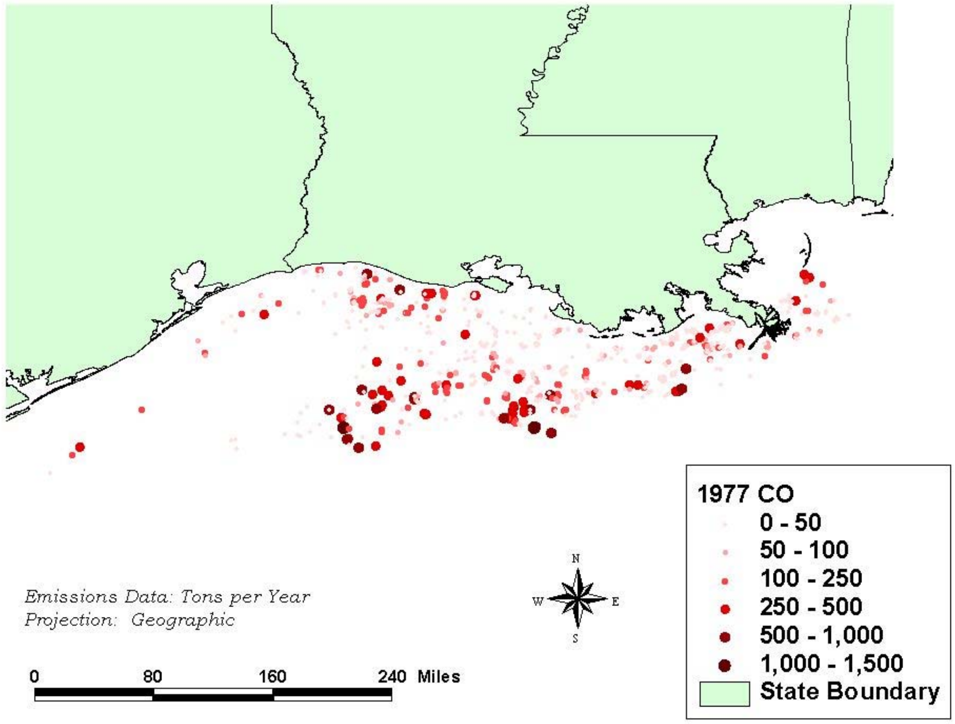


APPENDIX C

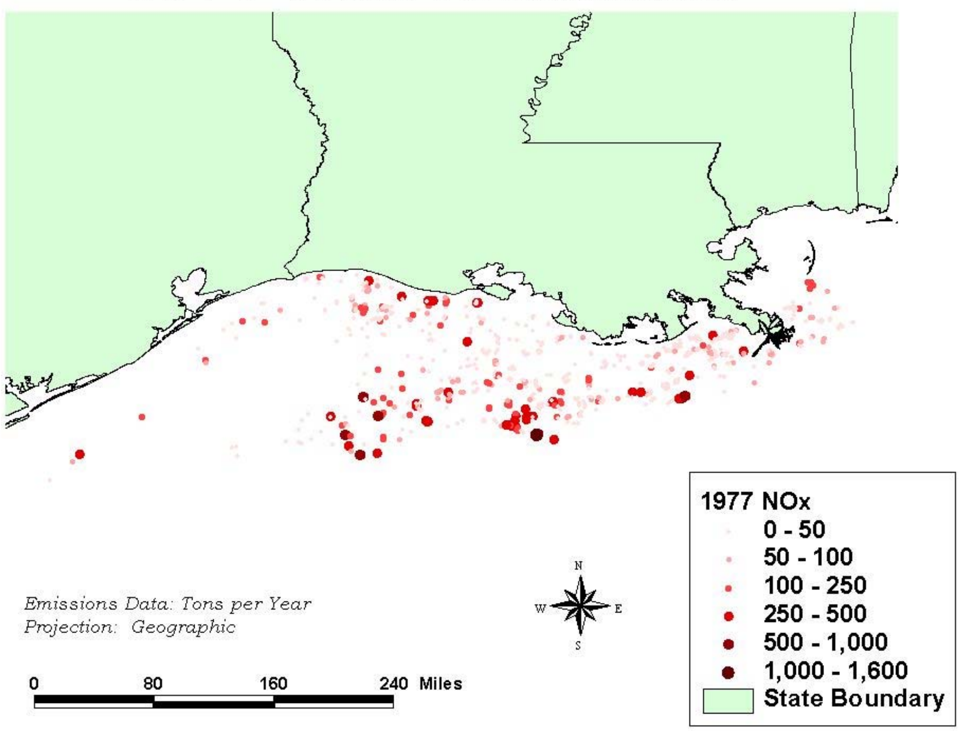
EMISSION PLOTS FOR PLATFORMS, 1977, 1988, AND 1993

The following plots depict emissions from platform sources in the Gulf of Mexico. The emissions quantities are displayed in tons per year. The maps are in geographic longitude and latitude format. All coordinates are NAD 27.

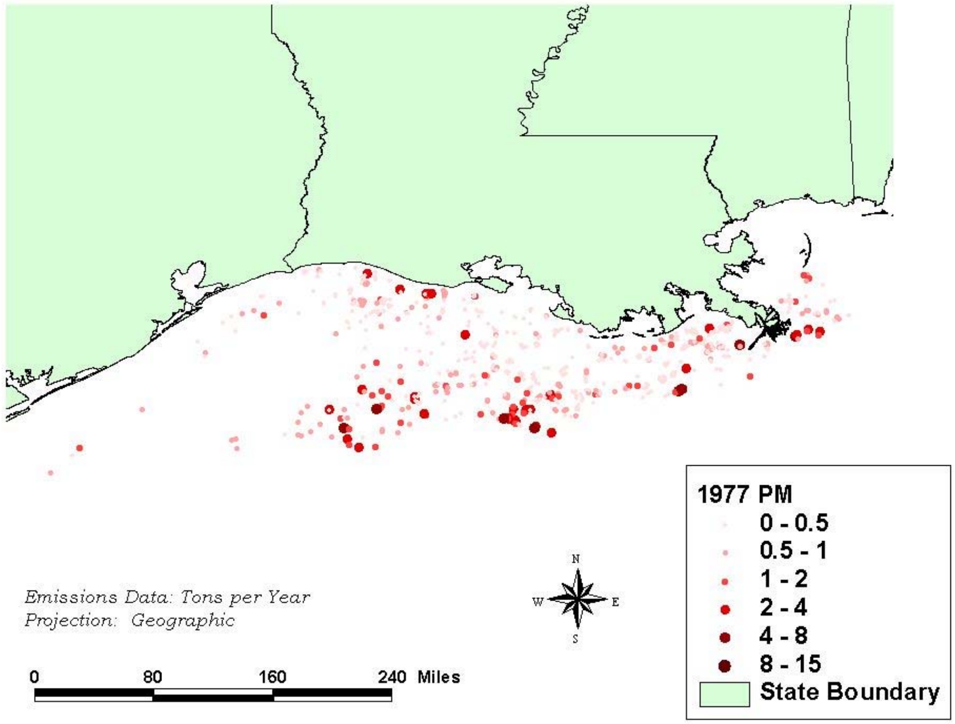
1977 CO Emissions



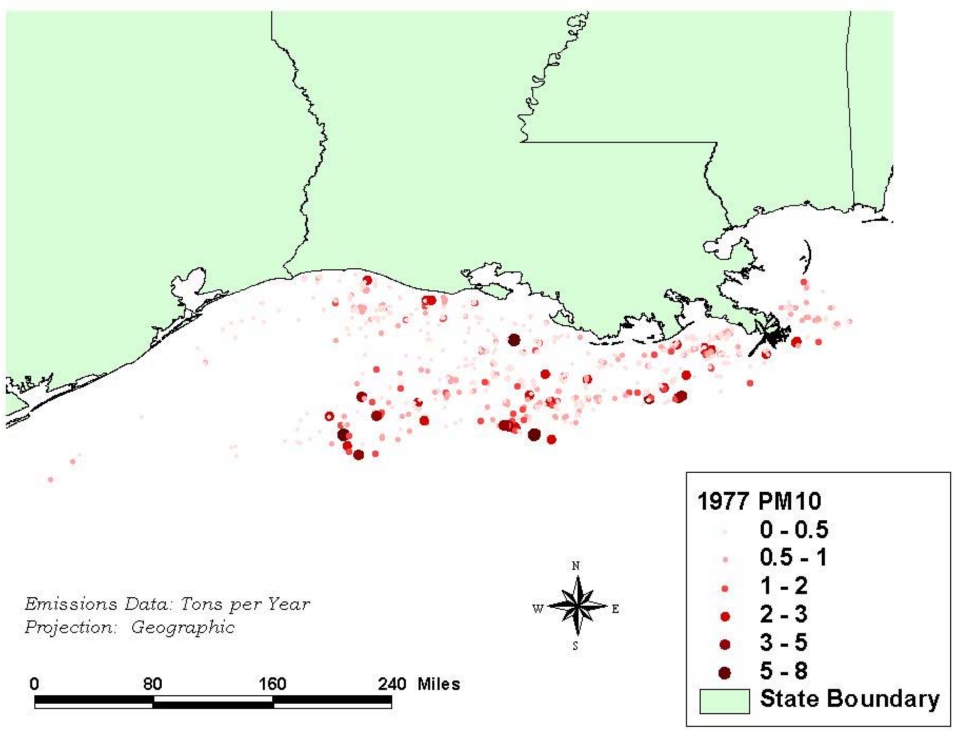
1977 NOx Emissions



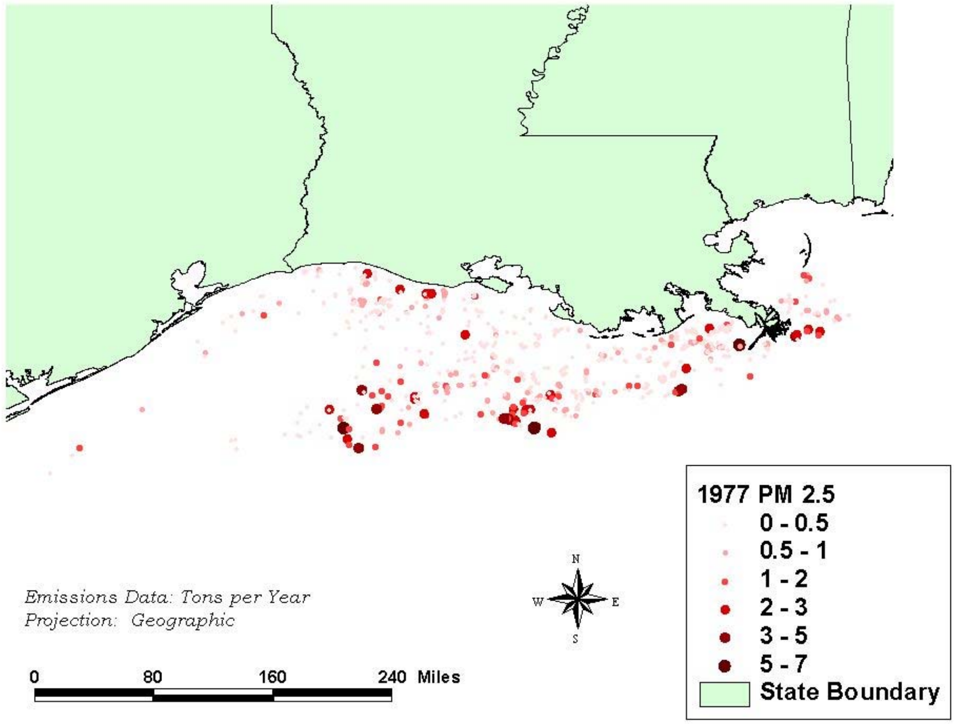
1977 PM Emissions



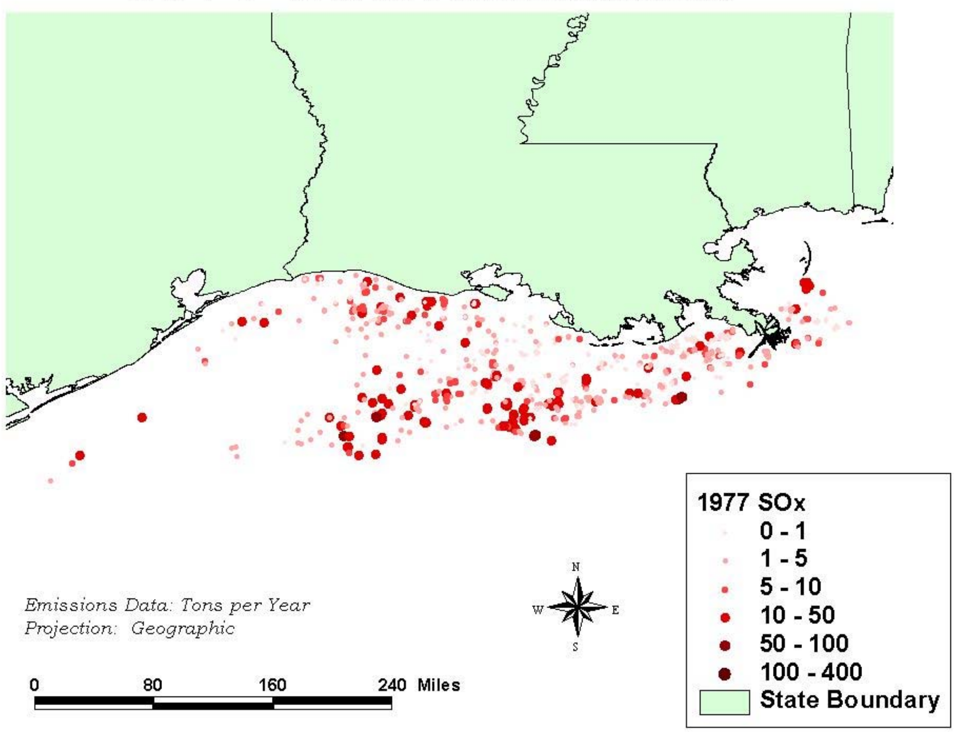
1977 PM10 Emissions



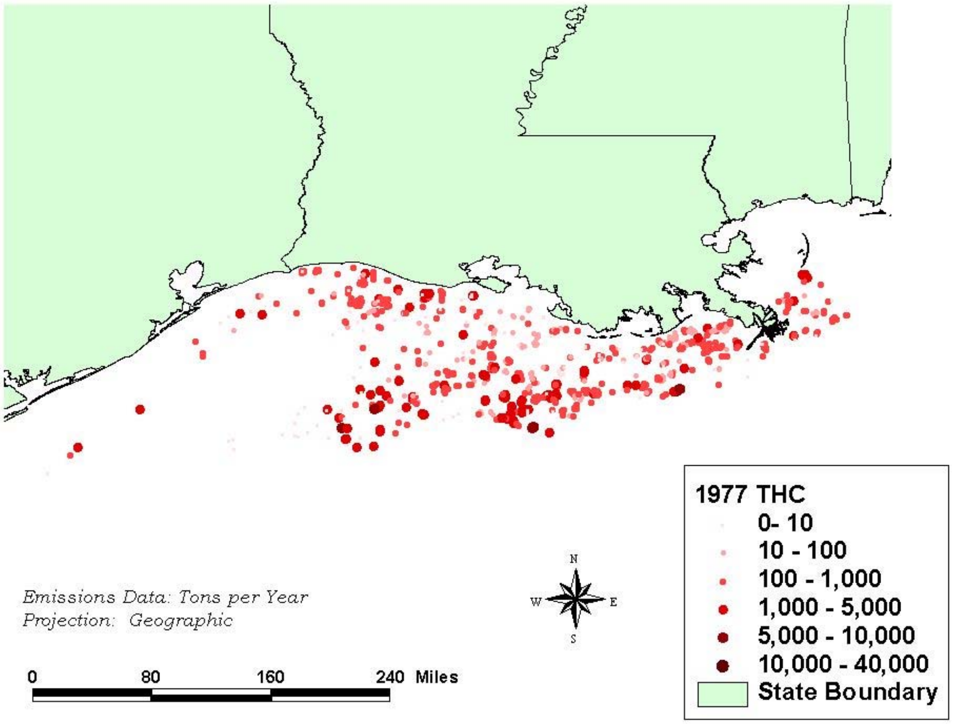
1977 PM2.5 Emissions



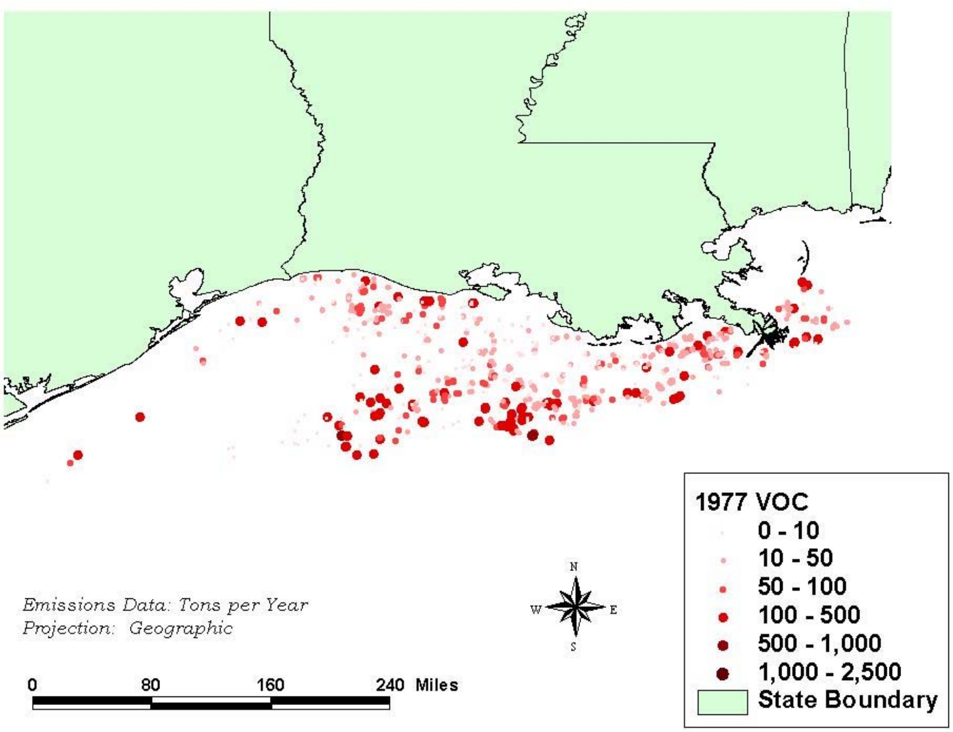
1977 SOx Emissions



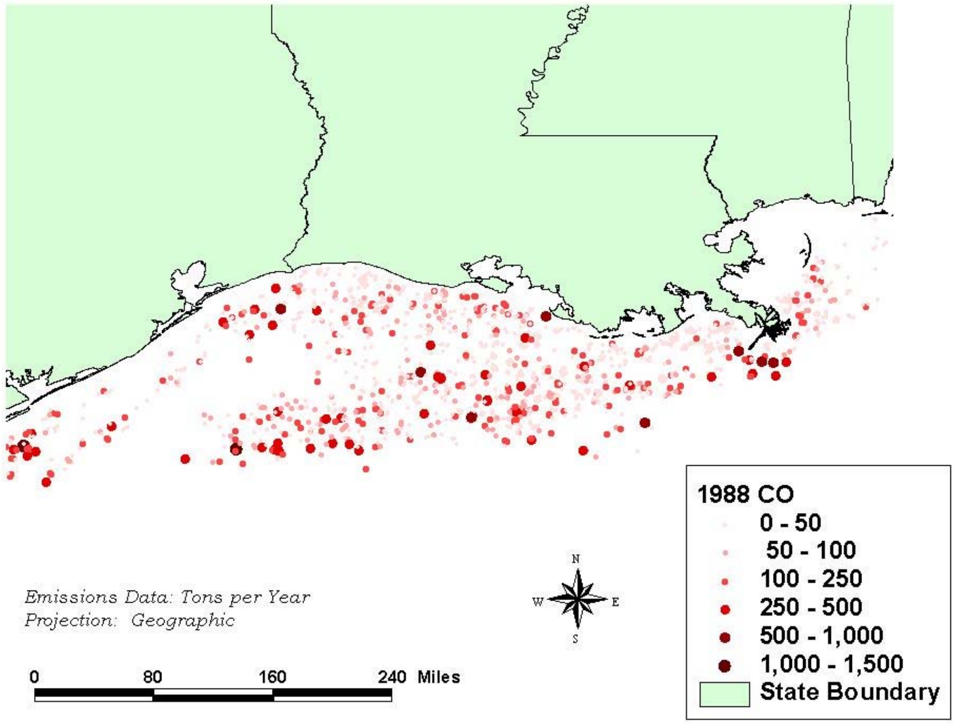
1977 THC Emissions



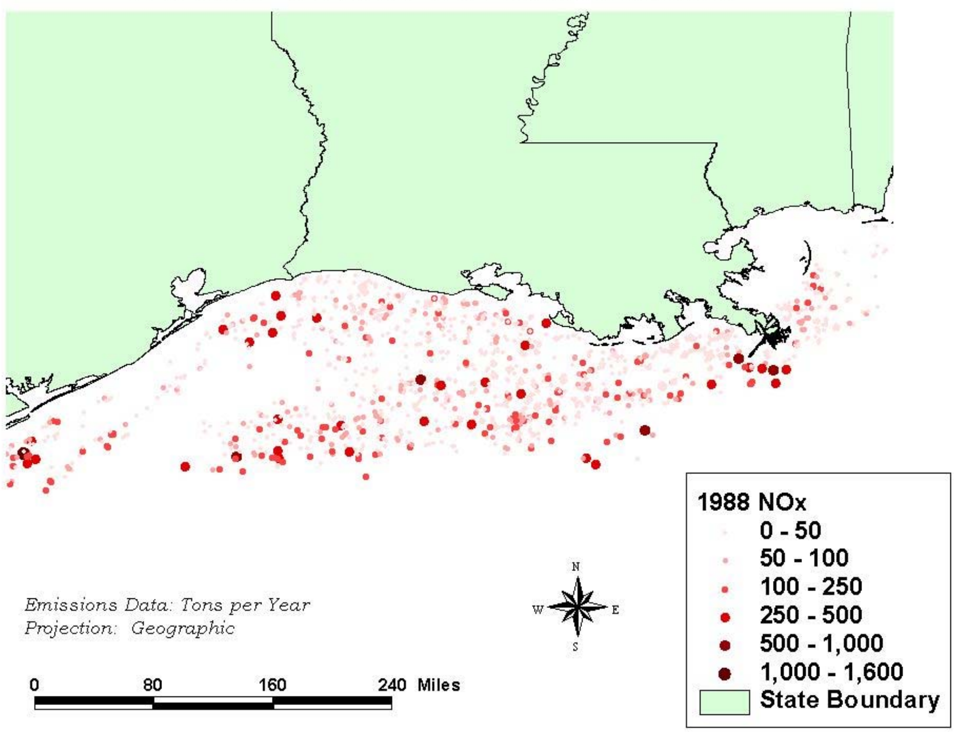
1977 VOC Emissions



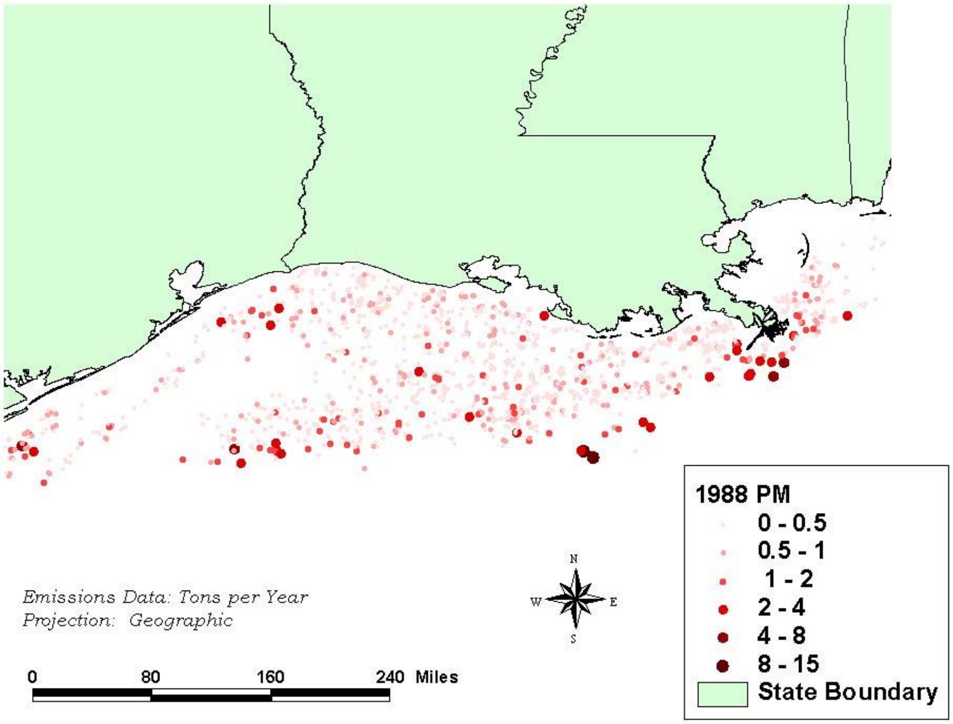
1988 CO Emissions



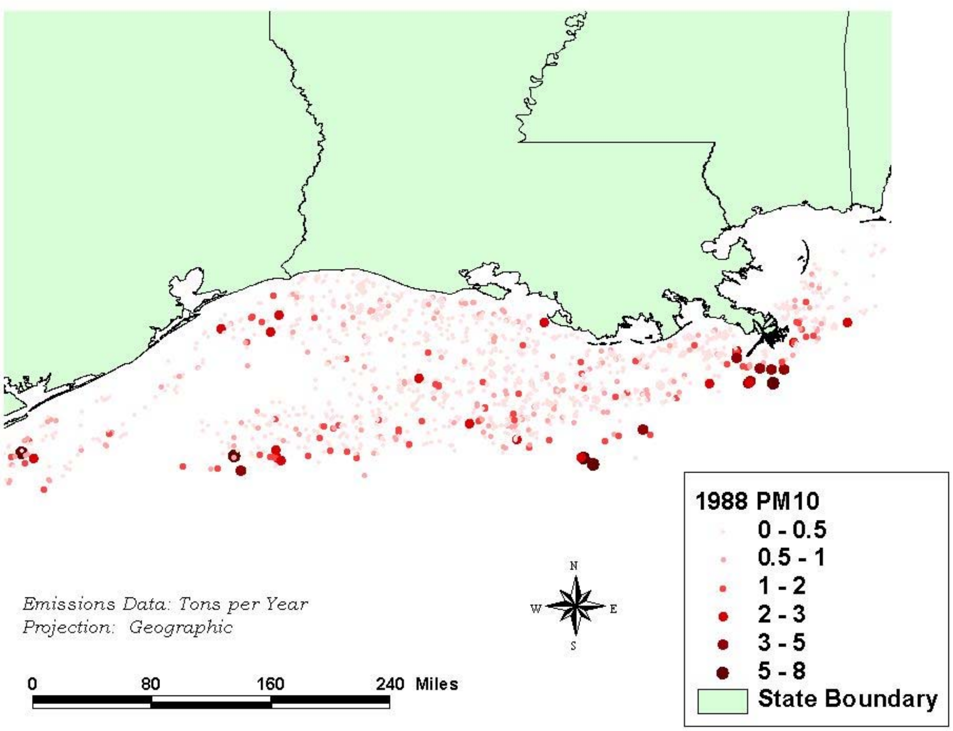
1988 NOx Emissions



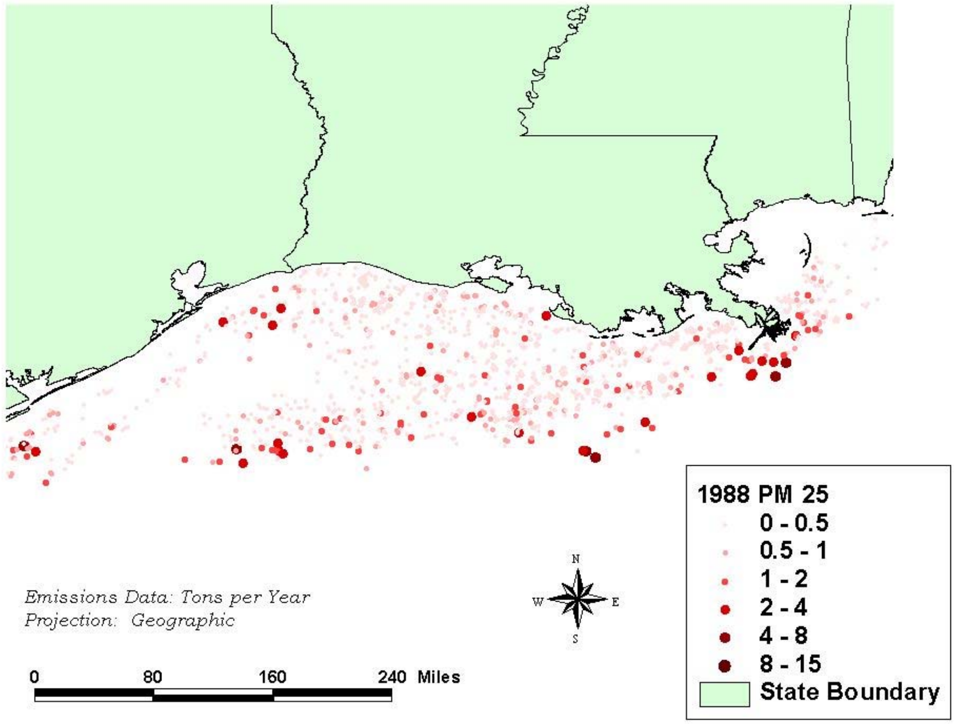
1988 PM Emissions



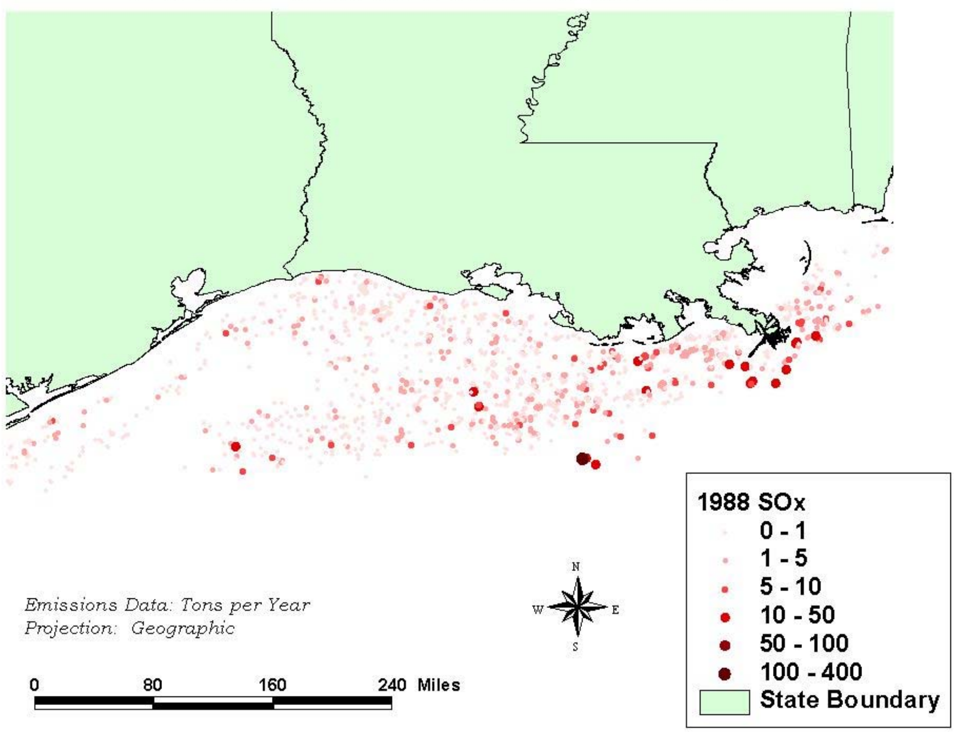
1988 PM10 Emissions



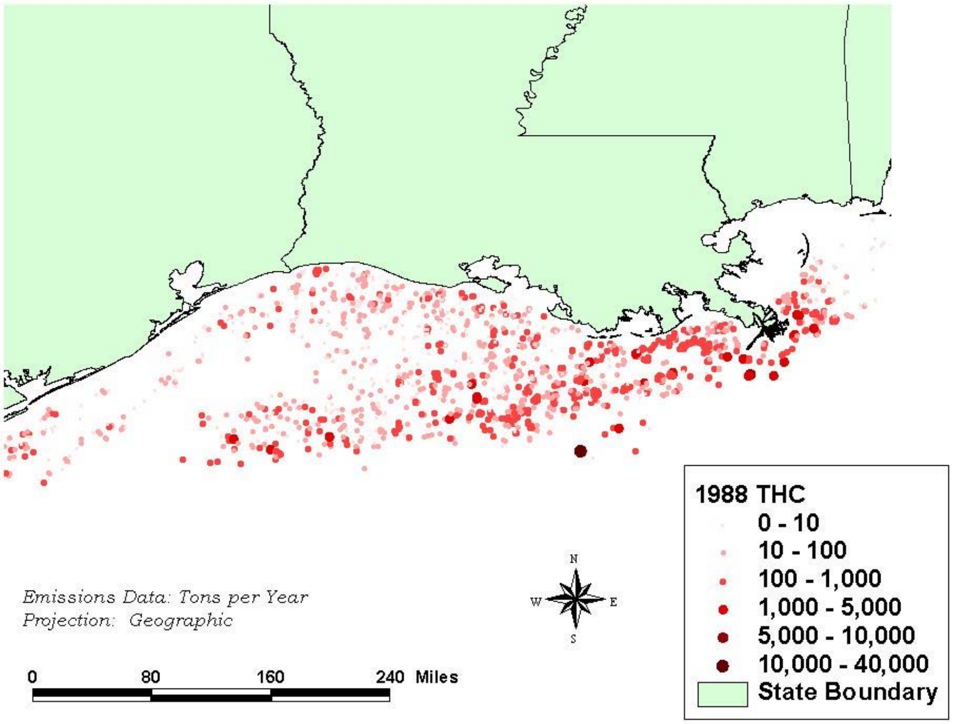
1988 PM2.5 Emissions



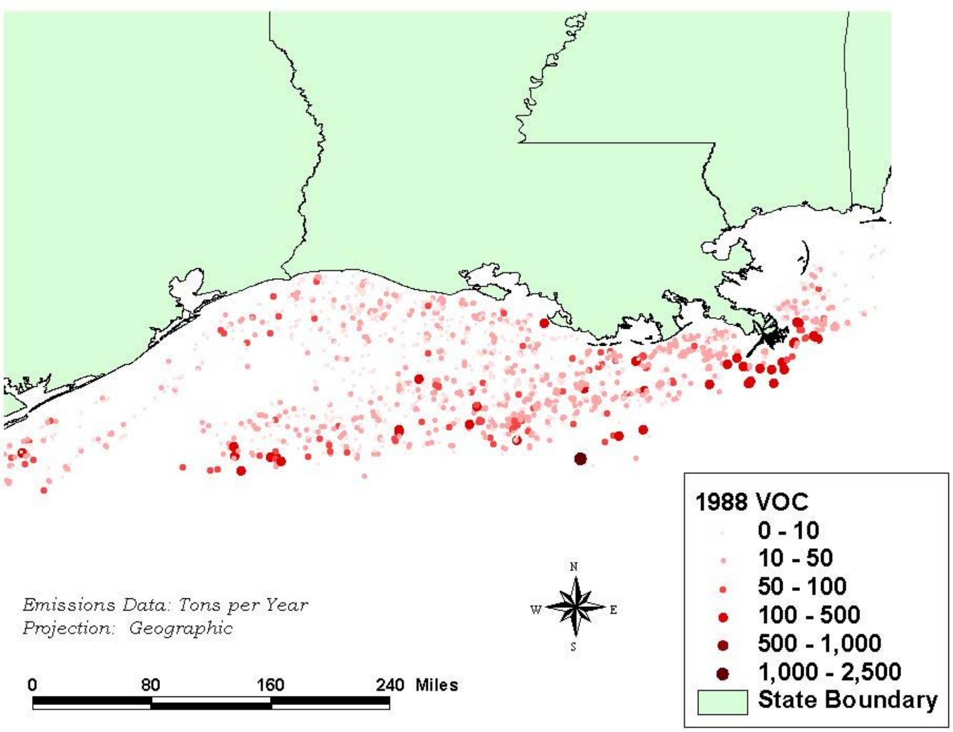
1988 SOx Emissions



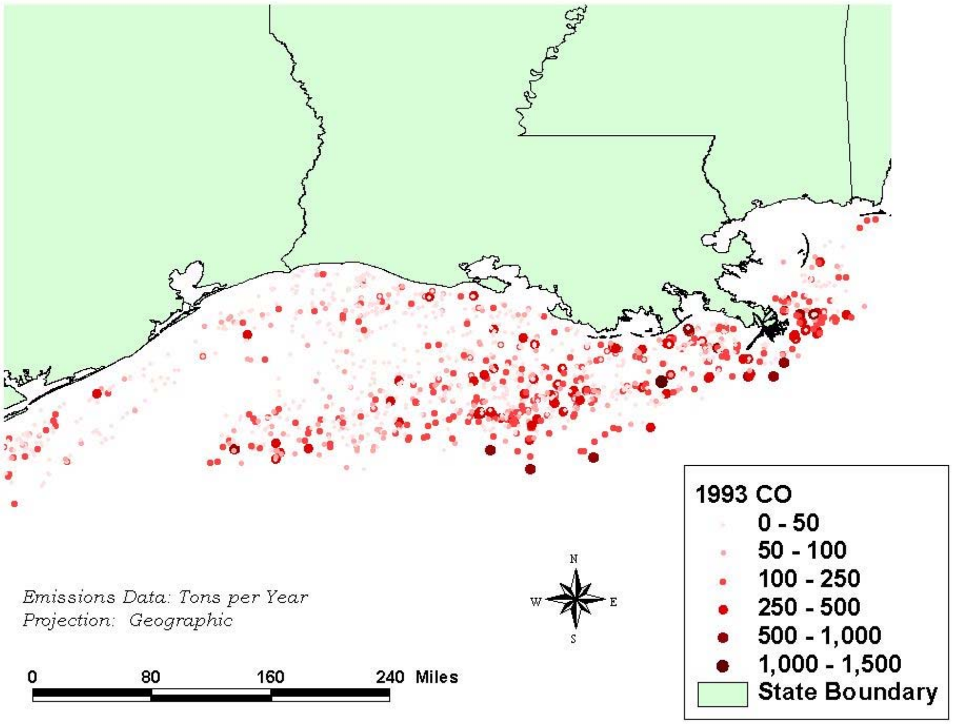
1988 THC Emissions



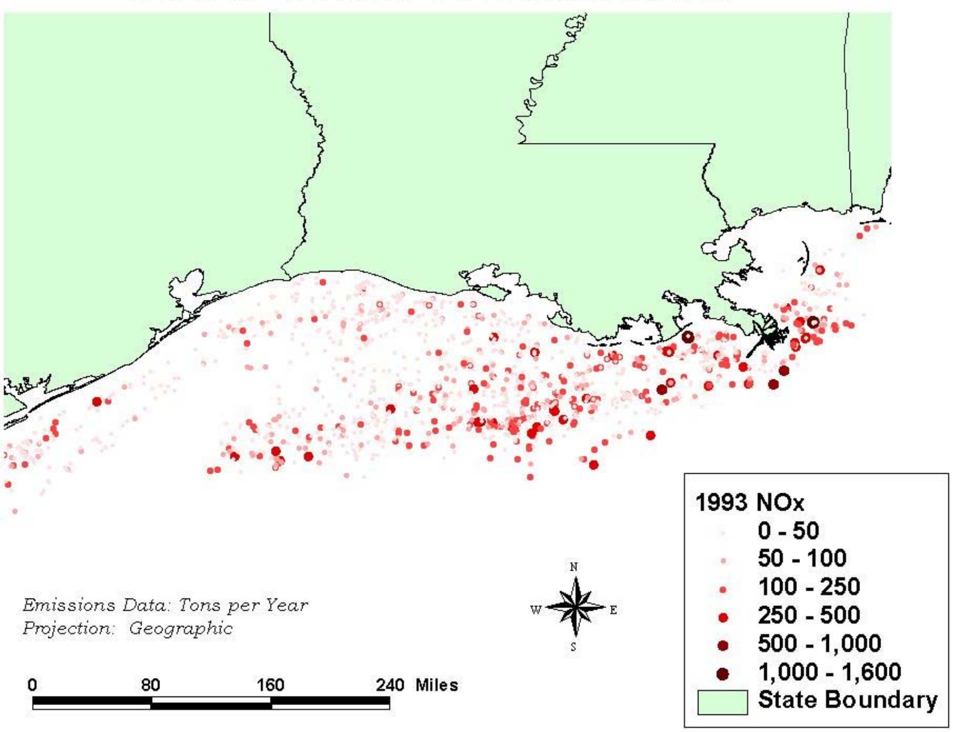
1988 VOC Emissions



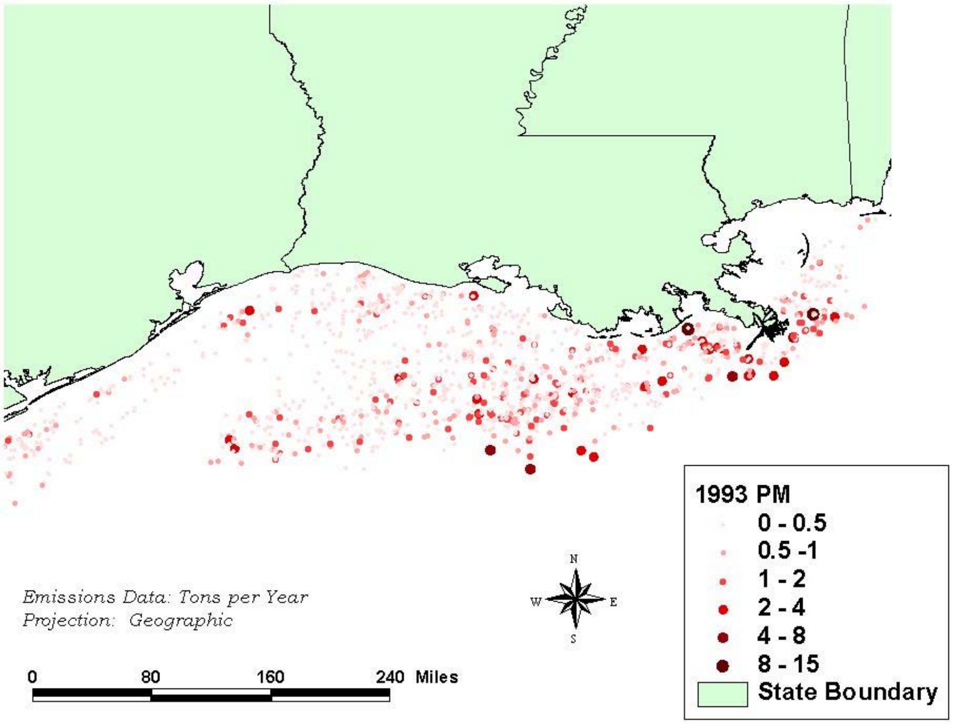
1993 CO Emissions



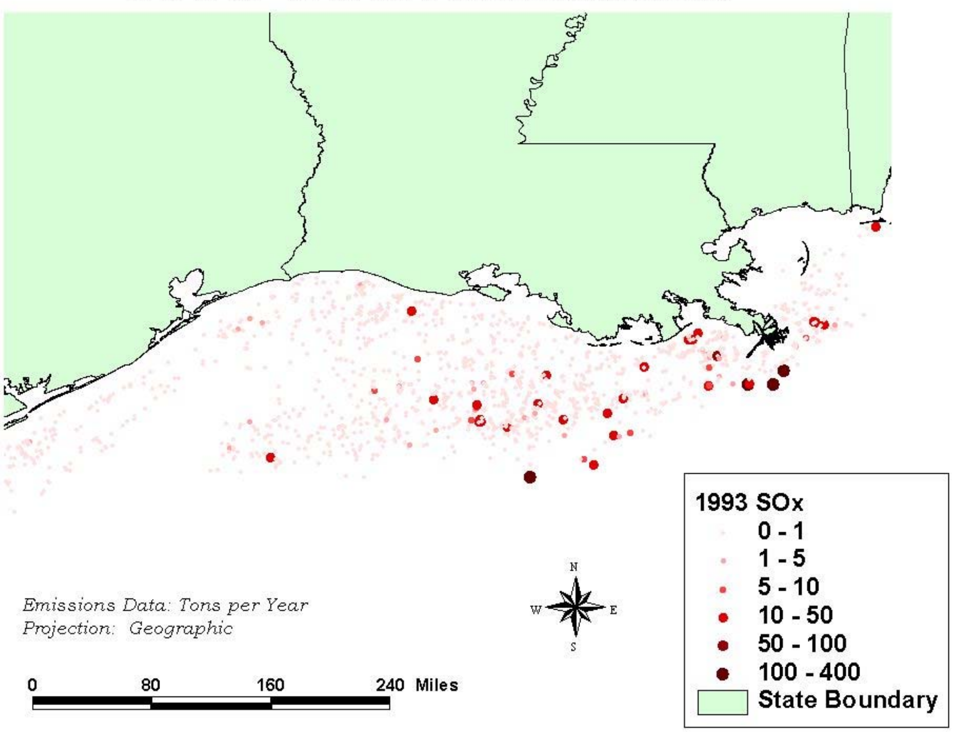
1993 NOx Emissions



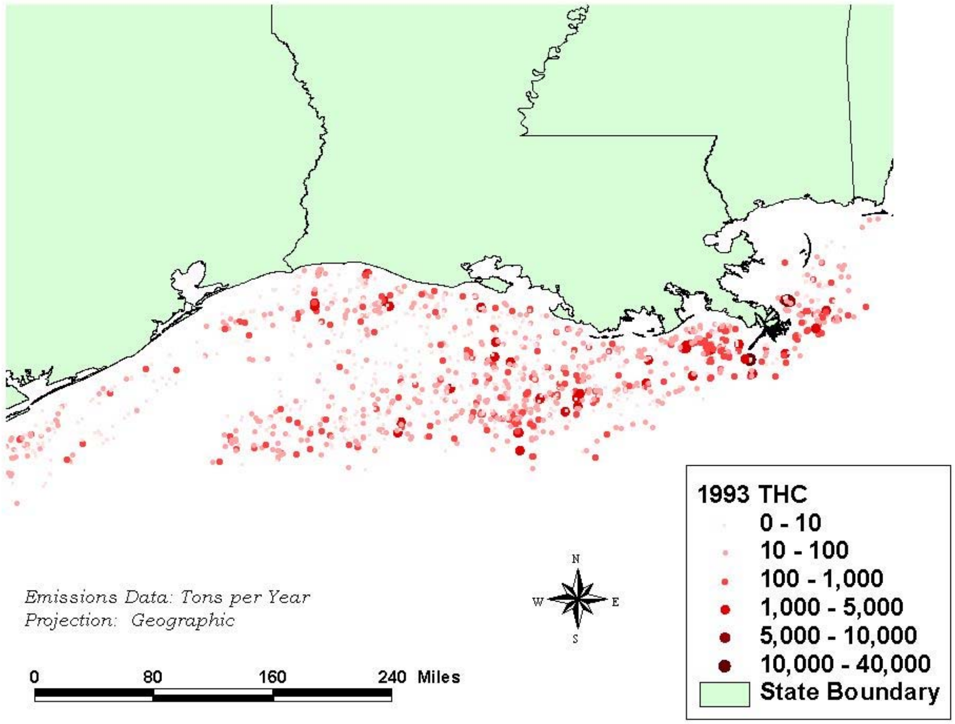
1993 PM Emissions



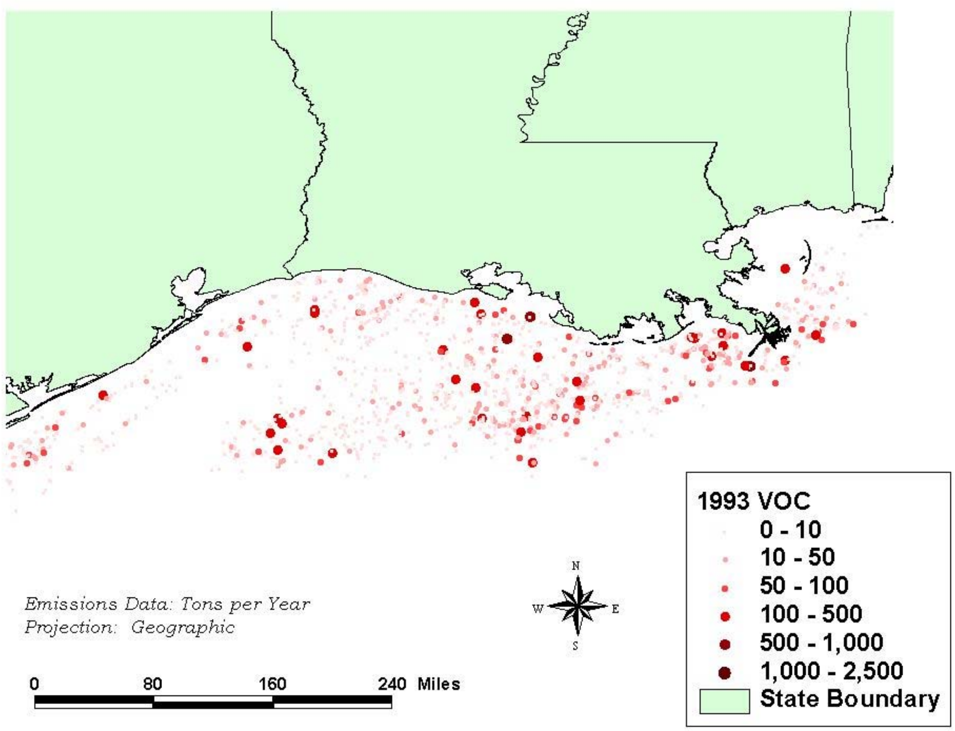
1993 SOx Emissions



1993 THC Emissions



1993 VOC Emissions



APPENDIX D

DATA STRUCTURE AND FORMAT FOR 1977 AND 1988 EMISSION INVENTORIES

The database contains five tables: HI_FLARING_ESTIMATES, MID_FLARING_ESTIMATES, LOW_FLARING_ESTIMATES, LOCATION, AND PARAMETER_DEFINITIONS. These tables and their relationships are described below.

The LOCATION table has 5,446 records. The primary key for this table is one unique identification field called SHORT_ID. This identification field is a code that represents each platform or well and its associated locational information. The columns in LOCATION are described in the table below.

Column Name	Type	Size	Possible Values	Description	Units
SHORT_ID	Long Integer	4	1 - 15,267	Numbers <10,000 are a platform id code, >10,000 are a well id code. This code corresponds to the SHORT_ID field in the "Location" Table.	N/A
MMS_ID	Text	14	Variable	MMS approved platform number (a concatenation of the complex id and structure number) **or** the API Well Number for boreholes	N/A
LATITUDE	Single	4	26.25186 - 30.18895	The latitude of the platform or well. Well coordinates are from the reported surface latitude.	Decimal degrees
LONGITUDE	Single	4	-97.13476 – (-84.05186)	The longitude of the platform or well. Well coordinates are from the reported surface longitude.	Decimal degrees
AC_LAB	Text	10	Variable	The two-digit MMS area code is joined with the block number to provide locational information for each platform and well.	N/A
OPERATOR_CODE	Long Integer	4	1 – 20643; Null	The MMS operator code provided with the Borehole and Platform datasets. Is Null when not available.	N/A

INSTALL_DATE[a]	Date/Time	8	1/1/48 - 2/15/98; Null	The MMS provided the installation date with the platform dataset and the “Total Depth Date” in the borehole dataset is used here as the installation date. Is Null when not available.	Date
REMOVAL_DATE[a]	Date/Time	8	12/31/75 - 7/5/01; Null	The MMS provided the removal date with the platform dataset. The closure of boreholes is not relevant to drilling emissions and is left null. Is Null when not available.	Date
SOURCE_TYPE	Text	10	PLATFORM; BOREHOLE	Identifies whether the locational information is for a borehole or platform source.	N/A

[a] Platforms with reported installation subsequent to the inventory years (1977-1992) were included in the MOADS emissions inventory. Additionally, platforms with a reported removal date prior to inventory years were also included in MOADS inventory. As the origin of this inconsistency is not evident, the MOADS platform data was retained in the final database. However, it is important to note that there are inconsistencies between the MOADS platform inventory and the platform installation/removal dates reported by MMS. The platforms that have this conundrum are outline in Appendix C.

The LOCATION table is related to the tables HI_FLARING_ESTIMATES, MID_FLARING_ESTIMATES, and LOW_FLARING_ESTIMATES by the “SHORT_ID” field. This field is the platform or well identifier and represents the same source in all tables. There is a one-to-many relationship between the LOCATION table and each of the emissions tables. This means that for every one “SHORT_ID” in the LOCATION table, there are many record with the same SHORT_ID in the emissions tables. However, for each of the many “SHORT_ID”s in the emissions tables each record is unique for the year, month, emissions type, and equipment source type.

HI_FLARING_ESTIMATES has 1,287,129 records. The primary key for this table is a combination of the columns: SHORT_ID, LEASE, EQUIP_TYPE, POLL_TYPE, YEAR, MONTH. This primary key assures that no monthly emissions from a platform for a specific lease is duplicated. Every record contains a unique value for monthly platform emissions for each source type from each active lease.

The columns in HI_FLARING_ESTIMATES are described below.

Column Name	Type	Size	Possible Values	Description	Units
SHORT_ID	Long Integer	4	1 - 15,267	Numbers <10,000 are a platform id code, >10,000 are a well id code. This code corresponds to the SHORT_ID field in the "Location" Table.	N/A
LEASE	Text	10	Variable	MMS Lease number	N/A
EQUIP_TYPE	Text	5	BOI, CON, DIE, DRILL, EQ, FL, GLY, GV, MUD, NGE, NGT, STO	Emissions source type: activity descriptor	N/A
POLL_TYPE	Text	4	CO, NO_x, SO_x, PM, PM_{10}, $PM_{2.5}$, THC, VOC	Emission type	N/A
YEAR	Integer	2	1977, 1988, 1993	Year emissions occurred	N/A
MONTH	Byte	1	1 - 12	Month emissions occurred	N/A
QUANTITY	Single	4	0 - 6,514,791	Quantity of emissions emitted by each emission source for each pollutant type	Pounds per month

Column values are listed below and are the same for HI_FLARING_ESTIMATES, MID_FLARING_ESTIMATES, and LOW_FLARING_ESTIMATES.

Parameter	**Column Name**	**Definition**	**Comments**
BOI	EQUIP_TYPE	Boiler equipment, all fuel type	Emission source type "BOI" is boiler related emissions specific to PM, PM10, and PM2.5
CO	POLL_TYPE	Carbon Monoxide	The emission type "Carbon Monoxide" is associated with flares, platform equipment, drilling rigs, and

			platform construction activities.
CON	EQUIP_TYPE	Platform construction equipment	Emissions source type "CON" is platform construction related emissions and includes NOx, CO, SOx, THC, VOC, PM, PM10, and PM2.5
DIE	EQUIP_TYPE	Diesel powered engines	Emissions source type "DIE" is diesel fueled reciprocating engines and turbines for PM, PM10, and PM2.5 specific emissions.
DRILL	EQUIP_TYPE	Drilling equipment	Emissions source type "DRILL" is drilling rig equipment and emissions include NOx, CO, SOx, THC, VOC, PM, PM10, and PM2.5
EQ	EQUIP_TYPE	All engines, boilers, and turbines	Emissions source type "EQ" groups emissions from boilers, turbines, and reciprocating engines and includes all emissions types except PM, PM10, and PM2.5.
FL	EQUIP_TYPE	Flare equipment	Emissions source type "FL" is flare related activity and includes emissions types NOx, SOx, CO, PM, PM10, and PM2.5
GLY	EQUIP_TYPE	Glycol units	Emissions source type "GLY" is glycol dehydrator unit activity related emissions and includes THC and VOC emission types
GV	EQUIP_TYPE	Gas venting equipment	Emissions source type "GV" is gas venting related activity and includes THC and VOC emission types
MUD	EQUIP_TYPE	Mud degassing	Emissions source type "MUD" is mud degassing activity and includes THC emissions
NGE	EQUIP_TYPE	Natural gas powered engines	Emissions source type "NGE" is natural gas fueled reciprocating engine activity and includes PM, PM10, and PM2.5 emission types
NGT	EQUIP_TYPE	Natural gas powered turbines	Emissions source type "NGT" is natural gas powered turbine activity and includes PM, PM10, and PM2.5 emission types.
NOx	POLL_TYPE	Oxides of Nitrogen	The emission type "NOx" is associated with flares, platform equipment, drilling rigs, and platform construction activities.

PM	POLL_TYPE	Total Particulate Matter	The emission type "PM" is associated with flares, platform equipment (type specific), drilling rigs, and platform construction activities.
PM10	POLL_TYPE	Particulate Matter of diameter 10 microns or less	The emission type "PM10" is associated with flares, platform equipment (type specific), drilling rigs, and platform construction activities.
PM25	POLL_TYPE	Particulate Matter of diameter 2.5 microns or less	The emission type "PM2.5" is associated with flares, platform equipment (type specific), drilling rigs, and platform construction activities.
SOx	POLL_TYPE	Oxides of Sulfur	The emission type "SOx" is associated with flares, platform equipment, drilling rigs, and platform construction activities.
STO	EQUIP_TYPE	Storage Tanks	Emissions source type "STO" is storage tank related emissions for THC and VOC emission types.
THC	POLL_TYPE	Total Hydrocarbon Compounds	The emission type "THC" is associated with gas venting, platform equipment, glycol units, storage tanks, drilling rigs, mud degassing, and platform construction activities.
VOC	POLL_TYPE	Volatile Organic Compounds	The emission type "VOC" is associated with gas venting, platform equipment, glycol units, storage tanks, drilling rigs, and platform construction activities.

MID_FLARING_ESTIMATES has 1,287,129 records. The primary key for this table is a combination of the columns: SHORT_ID, LEASE, EQUIP_TYPE, POLL_TYPE, YEAR, MONTH. This primary key assures that no monthly emissions from a platform for a specific lease is duplicated. Every record contains a unique value for monthly platform emissions for each source type from each active lease.

The columns in MID_FLARING_ESTIMATES are the same as HI_FLARING_ESTIMATES and are described below.

Column Name	Type	Size	Possible Values	Description	Units
SHORT_ID	Long Integer	4	1 - 15,267	Numbers <10,000 are a platform id code, >10,000 are a well id	N/A

				code. This code corresponds to the SHORT_ID field in the “Location” Table.	
LEASE	Text	10	Variable	MMS Lease number	N/A
EQUIP_TYPE	Text	5	BOI, CON, DIE, DRILL, EQ, FL, GLY, GV, MUD, NGE, NGT, STO	Emissions source type: activity descriptor	N/A
POLL_TYPE	Text	4	CO, NO_x, SO_x, PM, PM_{10}, $PM_{2.5}$, THC, VOC	Emission type	N/A
YEAR	Integer	2	1977, 1988, 1993	Year emissions occurred	N/A
MONTH	Byte	1	1 - 12	Month emissions occurred	N/A
QUANTITY	Single	4	0 – 6,644,437	Quantity of emissions emitted by each emission source for each pollutant type	Pounds per month

LOW_FLARING_ESTIMATES has 1,287,129 records. The primary key for this table is a combination of the columns: SHORT_ID, LEASE, EQUIP_TYPE, POLL_TYPE, YEAR, MONTH. This primary key assures that no monthly emissions from a platform for a specific lease is duplicated. Every record contains a unique value for monthly platform emissions for each source type from each active lease.

The columns in LOW_FLARING_ESTIMATES are described below.

Column Name	Type	Size	Possible Values	Description	Units
SHORT_ID	Long Integer	4	1 - 15,267	Numbers <10,000 are a platform id code, >10,000 are a well id code. This code corresponds to the SHORT_ID field in the “Location” Table.	N/A

LEASE	Text	10	Variable	MMS Lease number	N/A
EQUIP_TYPE	Text	5	BOI, CON, DIE, DRILL, EQ, FL, GLY, GV, MUD, NGE, NGT, STO	Emissions source type: activity descriptor	N/A
POLL_TYPE	Text	4	CO, NO_x, SO_x, PM, PM_{10}, $PM_{2.5}$, THC, VOC	Emission type	N/A
YEAR	Integer	2	1977, 1988, 1993	Year emissions occurred	N/A
MONTH	Byte	1	1 - 12	Month emissions occurred	N/A
QUANTITY	Single	4	0 – 7,640,350	Quantity of emissions emitted by each emission source for each pollutant type	Pounds per month

APPENDIX E

EMISSIONS CALCULATION PROCEDURES AND QUALITY CONTROL PROCEDURES FOR THE DATABASE MANAGEMENT SYSTEM

MEMORANDUM

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January 10, 2000 (revised September 17, 2000)

TO: Gaylen Drapé — STI Ref. No. 998202

FROM: Dana Coe and Lyle Chinkin

SUBJECT: Emissions calculations for amine units

Pollutants:
THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)
SO_x = Sulfur oxides (as sulfur dioxide, SO_2)

Summary:
Uncontrolled emissions of VOC and THC are calculated as follows:

$$E_{c,unc} = \frac{C_c}{100\%} \times \frac{EF_c}{100\%} \times Q \times 10^6 \times m_c \times \frac{lb \cdot mol}{379.4\ scf}$$

where:
$E_{c,unc}$ = Uncontrolled emissions of analyte *c* (pounds per month)
C_c = Concentration of analyte *c* in the natural gas, measured at the inlet to the amine unit (percent by volume)
EF_c = Quantity analyte *c* emitted when uncontrolled (percent)
Q = Volume of natural gas processed this month (million standard cubic feet, MMscf)
m_c = Molecular weight of analyte *c* (lb/lb-mol)

Emissions must be adjusted for any control devices that are installed, such as a flare, a pre-defined control device (a vapor recovery system/condenser, or a sulfur recovery unit), and/or some other user-specified control device. Controlled emissions of VOC and THC are calculated as follows:

$$E_{c,control} = E_{c,unc} \times \prod_d \frac{100 - Eff_{c,d}}{100\%}$$

where:
$E_{c,control}$ = Controlled emissions of analyte *c* (pounds per month)
$Eff_{c,d}$ = Control efficiency of control device *d* for analyte *c* (percent)

Devices that are intended to control hydrogen sulfide (H_2S) emissions, such as sulfur recovery units or flares, will produce emissions of SO_x as a by-product. Thus, if a flare and/or a sulfur recovery unit is present, SO_x emissions are calculated as follows. (If neither is present, the result of this equation will be zero.)

$$E_{SO_x,control} = \frac{C_{H_2S}}{100\%} \times \frac{EF_{H_2S}}{100\%} \times Q \times 10^6 \times \frac{lb \cdot mol}{379.4\ scf} \times \frac{2}{3} \times \left(\frac{3}{2} - \frac{A}{2}\right) \times \left(1 - \frac{\%RE}{100} \times A\right) \times \left(\frac{A}{2} + \frac{Eff_{H_2S}}{100}\right) \times \frac{64\ lb}{lb \cdot mol}$$

where:

%RE = Sulfur recovery efficiency of the Claus unit.
C = Concentration of H_2S in the Claus process stream (percent by volume)

$$A = \begin{cases} 0; \text{if no sulfur recovery unit is present} \\ 1; \text{if a sulfur recovery unit is present} \end{cases}$$

Assumptions:

Hydrocarbons are comprised of straight-chain, saturated hydrocarbons.
C9 or longer hydrocarbons are negligible.

Equations and Default Values:

New variables are shown in bold font. Variable names that exist in the BOADS tables are shown in italic font. Conditional values are preceded by IF (*condition = TRUE*) THEN statements.

Uncontrolled Emissions:

$$\mathbf{E_{THC,\,unc}} = ((\mathit{ConcMethane} \times \mathit{EmittedMethane} \times 16.04) + (\mathit{ConcEthane} \times \mathit{EmittedEthane} \times 30.07) + (\mathit{ConcC3HC} \times \mathit{EmittedC3HC} \times 44.10) + (\mathit{ConcC4HC} \times \mathit{EmittedC4HC} \times 58.12) + (\mathit{ConcC5HC} \times \mathit{EmittedC5HC} \times 72.15) + (\mathit{ConcC6HC} \times \mathit{EmittedC6HC} \times 86.18) + (\mathit{ConcC7HC} \times \mathit{EmittedC7HC} \times 100.21) + (\mathit{ConcC8plusHC} \times \mathit{EmittedC8plusHC} \times 114.23)) \times \mathit{TotalGasThru} \times 10\hat{}6 \div 379.4$$

$$\mathbf{E_{VOC,\,unc}} = ((\mathit{ConcC3HC} \times \mathit{EmittedC3HC} \times 44.10) + (\mathit{ConcC4HC} \times \mathit{EmittedC4HC} \times 58.12) + (\mathit{ConcC5HC} \times \mathit{EmittedC5HC} \times 72.15) + (\mathit{ConcC6HC} \times \mathit{EmittedC6HC} \times 86.18) + (\mathit{ConcC7HC} \times \mathit{EmittedC7HC} \times 100.21) + (\mathit{ConcC8plusHC} \times \mathit{EmittedC8plusHC} \times 114.23)) \times \mathrm{TotalGasThru} \times 10\hat{}6 \div 379.4$$

If values are not provided for any or all of *ConcC3HC*, *ConcC4HC*,…, *ConcC8plusHC*, estimate default values as follows (where $N_{missing}$ = the number of values among *ConcC3HC*, *ConcC4HC*,…, *ConcC8plusHC* that are null):

$\mathit{ConcC3HC}_{def}$ = (100 – (*ConcMethane* + *ConcEthane* + *ConcC3HC* + *ConcC4HC* + *ConcC7HC* + *ConcC8plusHC*) ÷ $N_{missing}$) ÷ 3
$\mathit{ConcC4HC}_{def}$ = (100 – (*ConcMethane* + *ConcEthane* + *ConcC3HC* + *ConcC4HC* + *ConcC7HC* + *ConcC8plusHC*) ÷ $N_{missing}$) ÷ 4
$\mathit{ConcC5HC}_{def}$ = (100 – (*ConcMethane* + *ConcEthane* + *ConcC3HC* + *ConcC4HC* + *ConcC7HC* + *ConcC8plusHC*) ÷ $N_{missing}$) ÷ 5
$\mathit{ConcC6HC}_{def}$ = (100 – (*ConcMethane* + *ConcEthane* + *ConcC3HC* + *ConcC4HC* + *ConcC7HC* + *ConcC8plusHC*) ÷ $N_{missing}$) ÷ 6
$\mathit{ConcC7HC}_{def}$ = 0
$\mathit{ConcC8plusHC}_{def}$ = 0
(Note: Treat null values as 0.)

If values are not provided for any or all of *EmittedC3HC*, *EmittedC4HC*,…, *EmittedC8plusHC*, assign default values in the following order:

EmitttedC3HC = *EmittedEthane*
EmittedC4HC = *Emitted C3HC*
EmittedC5HC = *Emitted C4HC*
EmittedC6HC = *Emitted C5HC*
EmittedC7HC = *EmittedC6HC*
EmittedC8plusHC = *EmittedC7HC*

Controlled Emissions:

$$\mathbf{E}_{\mathbf{THC,\ control}} = \mathbf{E}_{\mathbf{THC,\ unc}} \times (1 - \mathbf{Eff}_{\mathbf{THC,VF}} \div 100) \times (1 - \mathbf{Eff}_{\mathbf{THC,CT}} \div 100) \times (1 - \mathbf{Eff}_{\mathbf{THC,Oth}} \div 100)$$

$$\mathbf{E}_{\mathbf{VOC,\ control}} = \mathbf{E}_{\mathbf{VOC,\ unc}} \times (1 - \mathbf{Eff}_{\mathbf{VOC,VF}} \div 100) \times (1 - \mathbf{Eff}_{\mathbf{VOC,CT}} \div 100) \times (1 - \mathbf{Eff}_{\mathbf{VOC,Oth}} \div 100)$$

$$\begin{aligned}\mathbf{E}_{\mathbf{SOx,\ control}} &= \mathit{ConcNGH2S} \div 100 \times \mathit{EmittedH2S} \times 100 \times \mathit{TotalGasThru} \times 10\text{\^{}}6 \div 379.4 \times 2 \div 3 \times (1.5 - \mathbf{A}/2) \\ &\times (1 - \mathit{SRURecoveryEff} \div 100 \times \mathbf{A}) \times (0.5 \times \mathbf{A} + \mathbf{Eff}_{\mathbf{H2S,VF}} \div 100) \times 64 \times (1 - \mathbf{Eff}_{\mathbf{SOx,Oth}} \div 100)\end{aligned}$$

IF *GasesVentOrFlare* = “Vented” THEN
$Eff_{THC,VF} = Eff_{VOC,VF} = Eff_{H2S,VF} = 0$

IF *GasesVentOrFlare* = “Flared” or IF *VentedToID* is like *FLA* THEN
$Eff_{THC,VF} = Eff_{VOC,VF} = 98$
$Eff_{H2S,VF} = 95$

IF *ControlTechnology* = “none” THEN
$Eff_{THC,CT} = Eff_{VOC,CT} = 0$
A = 0

IF *ControlTechnology* = “VR/C” THEN
$Eff_{THC,CT} = Eff_{VOC,CT} = 80$
A = 0

IF *ControlTechnology* = “SR + VR/C” THEN
$Eff_{THC,CT} = Eff_{VOC,CT} = 80$
A = 1

IF *ControlTechnology* = “SR” THEN
$Eff_{THC,CT} = Eff_{VOC,CT} = 0$
A = 1

IF *OtherControlDevice* = “yes” THEN
$Eff_{THC,Oth} = Eff_{VOC,Oth} = \mathit{OtherControlEffVOC}$
$Eff_{SOx,Oth} = \mathit{OtherControlEffSOx}$
(Note: Treat null values as 0.)

IF *OtherControlDevice* = “no” THEN
$Eff_{THC,Oth} = Eff_{VOC,Oth} = 0$
$Eff_{SOx,Oth} = 0$

Statistics:
Percentiles of emissions magnitudes (THC, VOC, and SO_x) among the population of amine units.
Pro-rated THC, VOC, and SO_x emissions per processed throughput (pounds per MMscf per month), and their population percentiles.

Quality Control:
See BOADS QC specifications (Excel spreadsheet).
Flag if population percentiles are ≥ 98%.

MEMORANDUM

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March 21, 2001

TO: Gaylen Drapé and Suryamani Lingamallu STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions Calculations for Boilers, Heaters, and Burners

Pollutants:

THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)
SO_x = Sulfur oxides (as sulfur dioxide, SO_2)
NO_x = Nitrogen oxides (as nitrogen dioxide, NO_2)
PM_{10} = Particulate matter (with aerodynamic diameter of 10 µm or less)
CO = Carbon monoxide

Summary:

To calculate uncontrolled emissions for liquid-fueled engines (waste oil or diesel) based on fuel use, $E_{fu,liq}$:

$$E_{fu,\,liq} = EF_{(lb/10^3\ gal)} \times 10^{-3} \times U_{liq} \div 7.1\ \text{lb/gal}$$

To calculate uncontrolled emissions for gas-fueled engines (natural gas, process gas, or waste gas) based on fuel use, $E_{fu,gas}$:

$$E_{fu,gas} = EF_{(lb/MMscf)} \times 10^{-3} \times U_{gas}$$

where:

E = Emissions in pounds per month
EF = Emission factor (units are shown in parentheses)
U_{liq} = Fuel usage (pounds) = *TotalFuelUsedOil*
U_{gas} = Fuel usage (Mscf) = *TotalFuelUsed*

Emission Factors for Liquid-Fueled Units – Diesel
where *MaxRatedHeatInputRate* ≥ 100,
and *EmissionControls* as indicated.

	EmissionControls		
	"None"	"Low NOx Burner"	"Flu Gas Recirc"
Pollutant	EF_{liq} ($lb/10^3$ gal)		
THC	n/a	n/a	n/a
VOC	n/a	n/a	n/a
SO_x	$142 \times S_1$	$142 \times S_1$	$142 \times S_1$
NO_x	24	10	10
PM_{10}	2	2	2
CO	5	5	5

The SO_x emission factor varies with fuel sulfur content (ppmv) (S_1 = *FuelH2ScontentOil*).

Emission Factors for Liquid-Fueled Units – Diesel
where *MaxRatedHeatInputRate* < 100,
and *EmissionControls* as indicated.

	EmissionControls		
	"None"	"Low NOx Burner"	"Flu Gas Recirc"
Pollutant	EF_{liq} ($lb/10^3$ gal)		
THC	n/a	n/a	n/a
VOC	n/a	n/a	n/a
SO_x	$142 \times S_1$	$142 \times S_1$	$142 \times S_1$
NO_x	20	20	20
PM_{10}	2	2	2
CO	5	5	5

The SO_x emission factor varies with fuel sulfur content (ppmv) (S_1 = *FuelH2ScontentOil*).

Emission Factors for Liquid-Fueled Units – Waste Oil
where *MaxRatedHeatInputRate* ≥ 100,
and *EmissionControls* as indicated.

	EmissionControls		
	"None"	"Low NOx Burner"	"Flu Gas Recirc"
Pollutant	EF_{gas} (lb/MMscf)		
THC	n/a	n/a	n/a
VOC	n/a	n/a	n/a
SO_x	$157 \times S_1$	$157 \times S_1$	$157 \times S_1$
NO_x	47	40	40
PM_{10}	$9.19 \times S_1 + 3.22$	$9.19 \times S_1 + 3.22$	$9.19 \times S_1 + 3.22$
CO	5	5	5

The SO_x emission factor varies with fuel sulfur content (ppmv) (S_1 = *FuelH2ScontentOil*).

Emission Factors for Liquid-Fueled Units – Waste Oil
where *MaxRatedHeatInputRate* < 100,
and *EmissionControls* as indicated.

	EmissionControls		
	"None"	"Low NOx Burner"	"Flu Gas Recirc"
Pollutant	EF_{gas} (lb/MMscf)		
THC	n/a	n/a	n/a
VOC	n/a	n/a	n/a
SO_x	$157 \times S_1$	$157 \times S_1$	$157 \times S_1$
NO_x	55	55	55
PM_{10}	$9.19 \times S_1 + 3.22$	$9.19 \times S_1 + 3.22$	$9.19 \times S_1 + 3.22$
CO	5	5	5

The SO_x emission factor varies with fuel sulfur content (ppmv) (S_1 = *FuelH2ScontentOil*).

Emission Factors for Gas-Fueled Units – Natural Gas or Process Gas,
where *MaxRatedHeatInputRate* ≥ 100,
and *EmissionControls* as indicated.

	EmissionControls		
	"None"	"Low NOx Burner"	"Flu Gas Recirc"
Pollutant	EF_{gas} (lb/MMscf)		
THC	11	11	11
VOC	5.5	5.5	5.5
SO_x	$0.19 \times S_2$	$0.19 \times S_2$	$0.19 \times S_2$
NO_x	280	140	100
PM_{10}	7.6	7.6	7.6
CO	84	84	84

The SO_x emission factor varies with fuel sulfur content (ppmv) (S_2 = *FuelH2SContent*).

Emission Factors for Gas-Fueled Units – Natural Gas or Process Gas,
where *MaxRatedHeatInputRate* < 100,
and *EmissionControls* as indicated.

	EmissionControls		
	"None"	"Low NOx Burner"	"Flu Gas Recirc"
Pollutant	EF_{gas} (lb/MMscf)		
THC	11	11	11
VOC	5.5	5.5	5.5
SO_x	$0.19 \times S_2$	$0.19 \times S_2$	$0.19 \times S_2$
NO_x	100	50	32
PM_{10}	7.6	7.6	7.6
CO	84	84	84

The SO_x emission factor varies with fuel sulfur content (ppmv) (S_2 = *FuelH2SContent*).

These factors come from AP-42, Sections 1.3 and 3.4, dated September 1998 (with corrections/errata posted on EPA's website, 4/28/2000). All boilers are assumed to be wall-fired boilers (no tangential-fired boilers). Emission factors for No. 6 residual oil were used to estimate emissions from waste-oil-fueled units because waste oil combustion factors were in the same ballpark, but required ash content to calculate, and had no options for controls. Note that No. 2 fuel oil is the same thing as diesel.

If *FuelType* is "NATURAL GAS", "PROCESS GAS", or "WASTE GAS", then a value for *TotalFuelUsed* must be available or emissions cannot be calculated. Likewise, if *FuelType* is "WASTE OIL", or "DIESEL", then a value for *TotalFuelUsedOil* must be available or emissions cannot be calculated. Note that you cannot calculate SO_x emissions unless values for *FuelH2SContent* (if gas-fueled) or *FuelH2SContentOil* (if liquid-fueled) are available.

Default Values:

The following default values should be assigned or estimated if the corresponding fields are null.

$FuelH2Scontent_{default} = 3.18$

$FuelH2ScontentOil_{default} = 0.4$

$FuelHeatingValue_{default} = 1050$

$FuelHeatingValueOil_{default} = 19{,}300$

$FuelUsageRate_{default} = HeatInputRate \div FuelHeatingValue \times 10^6$

$FuelUsageRateOil_{default} = HeatInputRate \div FuelHeatingValueOil \times 10^6$

$TotalFuelUsed_{default} = FuelUsageRate \times HrsOperated \div 1000$

$TotalFuelUsedOil_{default} = FuelUsageRateOil \times HrsOperated$

where Fuel Usage Rate is expressed in terms of Mscf/hr

Controlled Emissions:

$\mathbf{E_{THC,\ control}} = \mathbf{E_{THC,\ uncontrolled}} \times (1 - \mathbf{Eff_{THC,Oth}} \div 100)$
$\mathbf{E_{VOC,\ control}} = \mathbf{E_{VOC,\ uncontrolled}} \times (1 - \mathbf{Eff_{VOC,Oth}} \div 100)$
$\mathbf{E_{SOx,\ control}} = \mathbf{E_{SOx,\ uncontrolled}} \times (1 - \mathbf{Eff_{SOx,Oth}} \div 100)$
$\mathbf{E_{NOx,\ control}} = \mathbf{E_{NOx,\ uncontrolled}} \times (1 - \mathbf{Eff_{NOx,Oth}} \div 100)$
$\mathbf{E_{PM10,\ control}} = \mathbf{E_{PM10,\ uncontrolled}} \times (1 - \mathbf{Eff_{PM10,Oth}} \div 100)$
$\mathbf{E_{CO,\ control}} = \mathbf{E_{CO,\ uncontrolled}} \times (1 - \mathbf{Eff_{CO,Oth}} \div 100)$

IF *OtherControlDevice* = “yes” THEN
- $Eff_{THC,Oth} = OtherControlEffVOC$
- $Eff_{VOC,Oth} = OtherControlEffVOC$
- $Eff_{SOx,Oth} = OtherControlEffSOx$
- $Eff_{NOx,Oth} = OtherControlEffNOx$
- $Eff_{PM10,Oth} = OtherControlEffPM10$
- $Eff_{CO,Oth} = OtherControlEffCO$
- (Note: Treat null values as 0.)

IF *OtherControlDevice* = “no” THEN
- $Eff_{THC,Oth} = 0$
- $Eff_{VOC,Oth} = 0$
- $Eff_{SOx,Oth} = 0$
- $Eff_{NOx,Oth} = 0$
- $Eff_{PM10,Oth} = 0$
- $Eff_{CO,Oth} = 0$

New QC Checks:

$MaxRatedHeatInputRate \geq HeatInputRate$

$MaxRatedFuelUsage \geq FuelUsageRate$

$MaxRatedFuelUsageOil \geq FuelUsageRateOil$

$0.8 \times TotalFuelUsed \leq HeatInputRate \div FuelHeatingValue \times HrsOperated \times 10^3 \leq 1.2 \times TotalFuelUsed$

$0.8 \times TotalFuelUsedOil \leq HeatInputRate \div FuelHeatingValueOil \times 10^6 \times HrsOperated \leq 1.2 \times TotalFuelUsedOil$

MEMORANDUM

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April 20, 2000

TO: Gaylen Drapé and Suryamani Lingamallu STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions Calculations for diesel and gasoline engines

Pollutants:

THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)
SO_x = Sulfur oxides (as sulfur dioxide, SO_2)
NO_x = Nitrogen oxides (as nitrogen dioxide, NO_2)
PM_{10} = Particulate matter (with aerodynamic diameter of 10 μm or less)
CO = Carbon monoxide

Summary:

To calculate uncontrolled emissions based on fuel use, E_{fu}:

$$E_{fu} = EF_{(lb/MMBtu)} \times 10^{-6} \times U \times \frac{7.1\,lb}{gal} \times H$$

To calculate uncontrolled emissions based on power output, E_{po}:

$$E_{po} = EF_{(g/hp\text{-}hr)} \times HP \times t \times \frac{lb}{453.6g}$$

where:

E = Emissions in pounds per month
EF = Emission factor (units are shown in parentheses)
U = Fuel usage (gallons) = *TotalFuelUsed*
H = Fuel heating value (BTU/lb) = *FuelHeatingValue*
HP = Engine horsepower (hp) = *OperatingHP*
t = Engine operating time (hr/month) = *HrsOperated*

Emission Factors for Gasoline Engines

Pollutant	EF_{fu} (lb/MMBtu)	EF_{po} (g/hp-hr)
THC	3.03	9.8
VOC	2.64	8.53
SO_x	0.084	0.268
NO_x	1.63	4.99
PM_{10}	0.1	0.327
CO	62.7	199

Emission Factors for Diesel Engines
where *MaxHP* < 600

Pollutant	EF_{fu} (lb/MMBtu)	EF_{po} (g/hp-hr)
THC	0.36	1.14
VOC	0.313	0.993
SO_x	0.29	0.93
NO_x	4.41	14.1
PM_{10}	0.31	1
CO	0.95	3.03

Emission Factors for Diesel Engines
where *MaxHP* ≥ 600

Pollutant	EF_{fu} (lb/MMBtu)	EF_{po} (g/hp-hr)
THC	0.09	0.32
VOC	0.0792	0.282
SO_x	$1.01 \times S$	$3.67 \times S$
NO_x	3.2	10.9
PM_{10}	0.057	0.182
CO	0.85	2.5

Note: The SO_x emission factor varies with fuel sulfur content (% by mass) (S = *FuelSulfurContent*).

These factors come from AP-42, Sections 3.3 and 3.4, dated October 1996.

If a user-entered value for *TotalFuelUsed* is available or if it can be estimated from the default values (below), then estimate emissions based upon fuel use. Otherwise, if *OperatingHP* and *HrsOperated* are both available, then estimate emissions based upon power output. If none of these conditions are met, don't calculate emissions. Note also that you cannot calculate emissions for natural gas engines unless the *MaxHP* is supplied. And, you cannot calculate SO_x emissions for natural gas engines where *MaxHP* ≥ 600 unless the *FuelSulfurContent* is supplied.

Default Values:

The following default values should be assigned or estimated if the corresponding fields are null.

$FuelHeatingValue_{default} = 19300$

Fuel Usage Rate = 7000

$TotalFuelUsed_{default} = FuelUsageRate \times 1/FuelHeatingValue \times 1/7.1 \times OperatingHP \times HrsOperated$

FuelSulfurContent = 0.4

where Fuel Usage Rate is expressed in terms of Btu/hp-hr.

Controlled Emissions:

$$\mathbf{E}_{\mathbf{THC,\ control}} = \mathbf{E}_{\mathbf{THC,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{THC,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{VOC,\ control}} = \mathbf{E}_{\mathbf{VOC,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{VOC,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{SOx,\ control}} = \mathbf{E}_{\mathbf{SOx,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{SOx,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{NOx,\ control}} = \mathbf{E}_{\mathbf{NOx,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{NOx,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{PM10,\ control}} = \mathbf{E}_{\mathbf{PM10,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{PM10,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{CO,\ control}} = \mathbf{E}_{\mathbf{CO,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{CO,Oth}} \div 100)$$

IF *OtherControlDevice* = “yes” THEN

$Eff_{THC,Oth} = OtherControlEffVOC$
$Eff_{VOC,Oth} = OtherControlEffVOC$
$Eff_{SOx,Oth} = OtherControlEffSOx$
$Eff_{NOx,Oth} = OtherControlEffNOx$
$Eff_{PM10,Oth} = OtherControlEffPM10$
$Eff_{CO,Oth} = OtherControlEffCO$
(Note: Treat null values as 0.)

IF *OtherControlDevice* = “no” THEN

$Eff_{THC,Oth} = 0$
$Eff_{VOC,Oth} = 0$
$Eff_{SOx,Oth} = 0$
$Eff_{NOx,Oth} = 0$
$Eff_{PM10,Oth} = 0$
$Eff_{CO,Oth} = 0$

New QC Checks:

$0.8 \times TotalFuelUsed \leq FuelUsageRate \times \ 1/FuelHeatingValue \times \ 1/7.1 \times OperatingHP \times HrsOperated \leq 1.2 \times TotalFuelUsed$

$FuelUsageRate \leq MaxRatedFuelUsage$

$OperatingHP \leq MaxHP$

MEMORANDUM

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September 14, 2000

TO: Gaylen Drapé and Suryamani Lingamallu — STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions calculations for drilling rigs

Pollutants:

THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)
SO_x = Sulfur oxides (as sulfur dioxide, SO_2)
NO_x = Nitrogen oxides (as nitrogen dioxide, NO_2)
PM_{10} = Particulate matter (with aerodynamic diameter of 10 μm or less)
CO = Carbon monoxide

Summary:

Total emissions equal the sum of emissions due to gasoline, diesel, and natural gas fuel usages ($E_{tot} = E_{gas} + E_{die} + E_{ng}$).

For gasoline fuel use, calculate uncontrolled emissions, E_{gas}, as follows:

$$E_{gas} = EF_{(lb/MMBtu)} \times 10^{-6} \times U \times \frac{7.1\text{ lb}}{\text{gal}} \times \frac{20{,}300\text{ Btu}}{\text{lb}}$$

where:
E = Emissions in pounds
EF = Emission factor (units are shown in parentheses)
U = Fuel usage (gallons) = *GasolineUsage*

For diesel fuel use, calculate uncontrolled emissions, E_{die}, as follows:

$$E_{die} = EF_{(lb/MMBtu)} \times 10^{-6} \times U \times \frac{7.1\text{ lb}}{\text{gal}} \times \frac{19{,}300\text{ Btu}}{\text{lb}}$$

where:

E = Emissions in pounds

EF = Emission factor (units are shown in parentheses)

U = Fuel usage (gallons) = *DieselUsage*

For natural gas fuel use, calculate uncontrolled emissions, E_{ng}, as follows:

$$E_{ng} = EF_{(lb/MMscf)} \times 10^{-3} \times U$$

where:

E = Emissions in pounds

EF = Emission factor (units are shown in parentheses)

U = Fuel usage (Mscf) = *NGUsage*

Emission Factors for Gasoline Fuel Use

Pollutant	EF_{gas} (lb/MMBtu)
THC	3.03
VOC	2.64
SO_x	0.084
NO_x	1.63
PM_{10}	0.1
CO	62.7

Emission Factors for Diesel Fuel Use

Pollutant	EF_{die} (lb/MMBtu)
THC	0.09
VOC	0.0792
SO_x	0.40
NO_x	3.2
PM_{10}	0.057
CO	0.85

Emission Factors for Natural Gas Fuel Use

Pollutant	EF_{ng} (lb/MMscf)
THC	1350
VOC	66
SO_x	0.57
NO_x	2743
PM_{10}	13
CO	880

These factors come from AP-42, Sections 3.2, 3.3, and 3.4, dated June 1997 and October 1996. Assume diesel engines are ≥ 600 hp. Assume NG engines are 4-cycle and evenly distributed between lean, clean, and rich burns (by averaging). Fuel sulfur contents are assumed to be 0.4% by mass for diesel engines and 3.18 ppmv for natural gas engines. For natural gas combustion, mid-range values were selected from the emission factors presented for the various engine designs.

Default Values:

No default values are necessary.

Controlled Emissions:

$$
\begin{aligned}
\mathbf{E_{THC,\ control}} &= \mathbf{E_{THC,\ uncontrolled}} \times (1 - \mathbf{Eff_{THC,Oth}} \div 100) \\
\mathbf{E_{VOC,\ control}} &= \mathbf{E_{VOC,\ uncontrolled}} \times (1 - \mathbf{Eff_{VOC,Oth}} \div 100) \\
\mathbf{E_{SOx,\ control}} &= \mathbf{E_{SOx,\ uncontrolled}} \times (1 - \mathbf{Eff_{SOx,Oth}} \div 100) \\
\mathbf{E_{NOx,\ control}} &= \mathbf{E_{NOx,\ uncontrolled}} \times (1 - \mathbf{Eff_{NOx,Oth}} \div 100) \\
\mathbf{E_{PM10,\ control}} &= \mathbf{E_{PM10,\ uncontrolled}} \times (1 - \mathbf{Eff_{PM10,Oth}} \div 100) \\
\mathbf{E_{CO,\ control}} &= \mathbf{E_{CO,\ uncontrolled}} \times (1 - \mathbf{Eff_{CO,Oth}} \div 100)
\end{aligned}
$$

IF *OtherControlDevice* = “yes” THEN

$Eff_{THC,Oth}$ = *OtherControlEffVOC*
$Eff_{VOC,Oth}$ = *OtherControlEffVOC*
$Eff_{SOx,Oth}$ = *OtherControlEffSOx*
$Eff_{NOx,Oth}$ = *OtherControlEffNOx*
$Eff_{PM10,Oth}$ = *OtherControlEffPM10*
$Eff_{CO,Oth}$ = *OtherControlEffCO*
(Note: Treat null values as 0.)

IF *OtherControlDevice* = “no” THEN

$Eff_{THC,Oth}$ = *0*
$Eff_{VOC,Oth}$ = *0*
$Eff_{SOx,Oth}$ = *0*
$Eff_{NOx,Oth}$ = *0*
$Eff_{PM10,Oth}$ = *0*
$Eff_{CO,Oth}$ = *0*

New QC Checks:

No new QC checks will be defined.

MEMORANDUM

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July 26, 2000

TO: Gaylen Drapé and Suryamani Lingamallu — STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions Calculations for Flares

For flares, note that some variables come from the eqFLA table, while others come from the eqFLAOCC table. Variables from the eqFLAOCC table are denoted with an asterisk (*).

Pollutants:
THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)
SO_x = Sulfur oxides (as sulfur dioxide, SO_2)
NO_x = Nitrogen oxides (as nitrogen dioxide, NO_2)
PM_{10} = Particulate matter (with aerodynamic diameter of 10 μm or less)
CO = Carbon monoxide

Summary:

Estimate flare emissions for THC, VOC, NO_x, PM_{10}, and CO according to the following equation.

$$E_{flare} = V_{tot} \times H \times EF_{flare} \div 1000$$

where:
E = Emissions in pounds
V_{tot} = Total volume of gas flared (Mscf) = $VolFlared + \sum(AvgFeed^* \times HrsOperated^*)$
H = Flare gas heating value (Btu/scf), assume equal to 1050 Btu/scf
EF_{flare} = Emission factor for flares (lb/MMBtu)

Estimate flare emissions of SO_x according to the following expression.

$$E_{flare,SO_x} = \left(\frac{Eff_F\%}{100\%}\right) \times \frac{10^{-6}}{ppm} \times \frac{m_{SO_2}}{379.4 scf/lb \cdot mol} \times 1000 \times \left(V' \times C_{H_2S} + \sum_{i=1}^{n} F_i^* \times t_i^* \times C_{H_2S,i}^*\right)$$

where:

$Eff_F\%$	=	The combustion efficiency of the flare (percent) = *FlareEfficiency*
m_{SO2}	=	Molecular weight of SO_2 = 64 lb/lb·mol
V'	=	Non-upset volume of gas flared (Mscf) = *VolFlared*
C_{H_2S}	=	Non-upset concentration of H_2S in the flare gas (ppmv) = *ConcH2S*
F_i^*	=	Upset flare feed rate for occurrence i (Mscf/hr) = *AvgFeed**
t_i^*	=	Duration of occurrence i = *HrsOperated**
$C_{H_2S,i}^*$	=	H_2S concentration for upset occurrence i = *ConcH2S* *

If *HasContFlarePilot* = "YES", estimate pilot light emissions according the following expression. (Otherwise, pilot light emissions are zero.)

$$E_{pilot} = P \times 30 \times EF_{pilot} \div 1000$$

where:

P	=	Flare feed rate (Mscf/day)
EF_{pilot}	=	Emission factor for pilot (lb/MMscf)

Emission Factors for Flares
where *FlareSmoke* as indicated.

Pollutant	EF (lb/MMBtu)
THC	0.14
VOC	0.052
NO_x	0.068
PM_{10}	0; where *FlareSmoke* = "NONE"
	0.002; where *FlareSmoke* = "LIGHT"
	0.01; where *FlareSmoke* = "MEDIUM"
	0.02; where *FlareSmoke* = "HEAVY"
CO	0.37

Emission Factors for Pilots.

Pollutant	EF (lb/MMscf)
THC	11
VOC	5.5
NO_x	100
PM_{10}	7.6
SO_x	0.6
CO	84

These factors come from AP-42, Section 13.5 (dated September 1991) and Section 1.4 (dated July 1998). Assume flare composition 45% C2/C3 and 55% C1 by volume to estimate VOC EF. For the pilot, a fuel sulfur content of 3.18 ppmv is assumed.

Default Values:

The following default values should be assigned or estimated if the corresponding fields are null.

$ConcH2S_{default} = 3.18$

$ConcH2S^*_{default} = 3.18$

$FlareEfficiency_{default} = 98$

$FlareSmoke_{default}$ = "LIGHT"

$VolFlared_{default} = StackExitVel \times \pi \div 4 \times (StackInnerDiam)^2 \div 144$

Controlled Emissions:

Note: For the following equations, E denotes total emissions ($E_{flare} + E_{pilot}$).

$$\mathbf{E_{THC,\ control}} = \mathbf{E_{THC,\ uncontrolled}} \times (1 - \mathbf{Eff_{THC,Oth}} \div 100)$$
$$\mathbf{E_{VOC,\ control}} = \mathbf{E_{VOC,\ uncontrolled}} \times (1 - \mathbf{Eff_{VOC,Oth}} \div 100)$$
$$\mathbf{E_{SOx,\ control}} = \mathbf{E_{SOx,\ uncontrolled}} \times (1 - \mathbf{Eff_{SOx,Oth}} \div 100)$$
$$\mathbf{E_{NOx,\ control}} = \mathbf{E_{NOx,\ uncontrolled}} \times (1 - \mathbf{Eff_{NOx,Oth}} \div 100)$$
$$\mathbf{E_{PM10,\ control}} = \mathbf{E_{PM10,\ uncontrolled}} \times (1 - \mathbf{Eff_{PM10,Oth}} \div 100)$$
$$\mathbf{E_{CO,\ control}} = \mathbf{E_{CO,\ uncontrolled}} \times (1 - \mathbf{Eff_{CO,Oth}} \div 100)$$

IF *OtherControlDevice* = “yes” THEN
$Eff_{THC,Oth} = OtherControlEffVOC$
$Eff_{VOC,Oth} = OtherControlEffVOC$
$Eff_{SOx,Oth} = OtherControlEffSOx$
$Eff_{NOx,Oth} = OtherControlEffNOx$
$Eff_{PM10,Oth} = OtherControlEffPM10$
$Eff_{CO,Oth} = OtherControlEffCO$
(Note: Treat null values as 0.)

IF *OtherControlDevice* = “no” THEN
$Eff_{THC,Oth} = 0$
$Eff_{VOC,Oth} = 0$
$Eff_{SOx,Oth} = 0$
$Eff_{NOx,Oth} = 0$
$Eff_{PM10,Oth} = 0$
$Eff_{CO,Oth} = 0$

New QC Check:

$0.8 \times \text{StackExitVel} \times \pi \div 4 \times (\text{StackInnerDiam})^2 \div 144 \leq \text{VolFlared} \leq 1.2 \times \text{StackExitVel} \times \pi \div 4 \times (\text{StackInnerDiam})^2 \div 144$

MEMORANDUM

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July 26, 2000

TO: Gaylen Drapé and Suryamani Lingamallu STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions Calculations for Fugitives

Pollutants:
THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)

Summary:

If any component counts are provided, estimate uncontrolled fugitive THC emissions according to the following equation. (Note that the sum is taken over 16 component types.)

$$E_{THC} = (720\ \text{hr/month}) \times \sum_{comp} \left(EF_{comp,stream} \times N_{comp} \right)$$

where:

$EF_{comp,stream}$ = Emission factor unique the type of component and process stream (lb/hr-component)

stream = *StreamType*

N_{comp} = Count of components of a given type present on the facility. There are 16 component types, with counts given the following variable names: *Valves*, *PumpSeals*, *Connectors*, *Flanges*, *OpenEndedLines*, *Compressors*, *Diaphragms*, *Drains*, *DumpArms*, *Hatches*, *Instruments*, *Meters*, *PressureReliefValves*, *PolishedRods*, *OtherReliefValves*, *Vents*. (Note: Treat null values as zero.)

If any component counts are provided, estimate uncontrolled fugitive VOC emissions according to the following equation. (Note that the sum is taken over 16 component types.)

$$E_{VOC} = (720\ \text{hr/month}) \times \sum_{comp} \left(EF_{comp,stream} \times N_{comp} \times WtFr_{comp,stream} \right)$$

where:

$WtFr_{comp,stream}$ = Weight fraction of VOC unique to the type of component and process stream

THC emission factors and VOC weight fractions are included in an excel spreadsheet (FugitiveFactors.xls).[1,2]

If no component counts are provided, estimate emissions according to the following equations.

$$E_{THC} = (720 \text{ hr/month}) \times EF_{default} \times N_{default}$$

$$E_{VOC} = (720 \text{ hr/month}) \times EF_{default} \times N_{default} \times WtFr_{default}$$

where:

$EF_{default}$ = 0.0308 lb/hr-component

$$N_{default} = \begin{cases} 1000; \text{if FacilitySize} = \text{"Small (<= 1000 components)"} \\ 10{,}000; \text{if FacilitySize} = \text{"Medium (1000 - 10,000 components)"} \\ 100{,}000; \text{if FacilitySize} = \text{"Large (> 10,000 components)"} \end{cases}$$

$WtFr_{default}$ = The default VOC weight fraction = *WeightPercentVOC* ÷ 100

Default Values:

The following default value should be assigned or estimated if the field is null.

WeightPercentVOC = 29.6

Controlled Emissions:

$$\mathbf{E_{THC,\ control}} = \mathbf{E_{THC,\ uncontrolled}} \times (1 - \mathbf{Eff_{THC,Oth}} \div 100)$$
$$\mathbf{E_{VOC,\ control}} = \mathbf{E_{VOC,\ uncontrolled}} \times (1 - \mathbf{Eff_{VOC,Oth}} \div 100)$$

IF *OtherControlDevice* = “yes” THEN
$Eff_{THC,Oth}$ = *OtherControlEffVOC*
$Eff_{VOC,Oth}$ = *OtherControlEffVOC*
(Note: Treat null values as 0.)

IF *OtherControlDevice* = “no” THEN
$Eff_{THC,Oth} = 0$
$Eff_{VOC,Oth} = 0$

New QC Check:

There are no new QC checks.

---

[1] Note that the emission factor for Comp=Pumps, Stream=Heavy Oil was assumed to be equal to the emission factor for Comp=Pumps, Stream=Light Oil. No published emission factor is available. This assumption will produce a conservatively high estimate.

[2] Also note that the emission factors and VOC weight fractions for Stream=Gas/Oil/Water were assumed to be equal to the larger of the EFs and/or WFs for Stream=Gas and Stream=Oil/Water. Again, no published data are available. However, these assumptions will produce conservatively high estimates.

Emission factors and VOC weight fractions for fugitive emissions. (See FugitiveFactors.xls)

Component Type	Stream Type	EF(lb/hr-comp)	VOC Weight Fraction
Connectors	Gas	0.000458	0.171
Connectors	NGL	0.000458	0.296
Connectors	Light Oil (>=20 API gr.)	0.000458	0.296
Connectors	Heavy Oil (<20 API gr.)	0.0000167	0.03
Connectors	Oil/Water	0.000242	0.296
Connectors	Oil/Water/Gas	0.000458	0.296
Flanges	Gas	0.000875	0.171
Flanges	NGL	0.000242	0.296
Flanges	Light Oil (>=20 API gr.)	0.000242	0.296
Flanges	Heavy Oil (<20 API gr.)	0.000000875	0.03
Flanges	Oil/Water	0.00000625	0.296
Flanges	Oil/Water/Gas	0.000875	0.296
Open-ended Lines	Gas	0.00458	0.171
Open-ended Lines	NGL	0.00308	0.296
Open-ended Lines	Light Oil (>=20 API gr.)	0.00308	0.296
Open-ended Lines	Heavy Oil (<20 API gr.)	0.00308	0.03
Open-ended Lines	Oil/Water	0.000542	0.296
Open-ended Lines	Oil/Water/Gas	0.00458	0.296
Pumps	Gas	0.00542	0.171
Pumps	NGL	0.0288	0.296
Pumps	Light Oil (>=20 API gr.)	0.0288	0.296
Pumps	Heavy Oil (<20 API gr.)	0.0288	0.03
Pumps	Oil/Water	0.0000542	0.296
Pumps	Oil/Water/Gas	0.00542	0.296
Valves	Gas	0.01	0.171
Valves	NGL	0.00542	0.296
Valves	Light Oil (>=20 API gr.)	0.00542	0.296
Valves	Heavy Oil (<20 API gr.)	0.0000183	0.03
Valves	Oil/Water	0.000217	0.296
Valves	Oil/Water/Gas	0.01	0.296
Sample Connections	Gas	0.00458	0.171
Sample Connections	NGL	0.00308	0.296
Sample Connections	Light Oil (>=20 API gr.)	0.00308	0.296
Sample Connections	Heavy Oil (<20 API gr.)	0.00308	0.03
Sample Connections	Oil/Water	0.000542	0.296
Sample Connections	Oil/Water/Gas	0.00458	0.296
Compressor Seals	Gas	0.0196	0.171
Compressor Seals	NGL	0.0167	0.296
Compressor Seals	Light Oil (>=20 API gr.)	0.0167	0.296
Compressor Seals	Heavy Oil (<20 API gr.)	0.0000708	0.03
Compressor Seals	Oil/Water	0.0308	0.296

Component Type	Stream Type	EF(lb/hr-comp)	VOC Weight Fraction
Compressor Seals	Oil/Water/Gas	0.0308	0.296
Diaphragms	Gas	0.0196	0.171
Diaphragms	NGL	0.0167	0.296
Diaphragms	Light Oil (>=20 API gr.)	0.0167	0.296
Diaphragms	Heavy Oil (<20 API gr.)	0.0000708	0.03
Diaphragms	Oil/Water	0.0308	0.296
Diaphragms	Oil/Water/Gas	0.0308	0.296
Drains	Gas	0.0196	0.171
Drains	NGL	0.0167	0.296
Drains	Light Oil (>=20 API gr.)	0.0167	0.296
Drains	Heavy Oil (<20 API gr.)	0.0000708	0.03
Drains	Oil/Water	0.0308	0.296
Drains	Oil/Water/Gas	0.0308	0.296
Dump Arms	Gas	0.0196	0.171
Dump Arms	NGL	0.0167	0.296
Dump Arms	Light Oil (>=20 API gr.)	0.0167	0.296
Dump Arms	Heavy Oil (<20 API gr.)	0.0000708	0.03
Dump Arms	Oil/Water	0.0308	0.296
Dump Arms	Oil/Water/Gas	0.0308	0.296
Hatches	Gas	0.0196	0.171
Hatches	NGL	0.0167	0.296
Hatches	Light Oil (>=20 API gr.)	0.0167	0.296
Hatches	Heavy Oil (<20 API gr.)	0.0000708	0.03
Hatches	Oil/Water	0.0308	0.296
Hatches	Oil/Water/Gas	0.0308	0.296
Instruments	Gas	0.0196	0.171
Instruments	NGL	0.0167	0.296
Instruments	Light Oil (>=20 API gr.)	0.0167	0.296
Instruments	Heavy Oil (<20 API gr.)	0.0000708	0.03
Instruments	Oil/Water	0.0308	0.296
Instruments	Oil/Water/Gas	0.0308	0.296
Meters	Gas	0.0196	0.171
Meters	NGL	0.0167	0.296
Meters	Light Oil (>=20 API gr.)	0.0167	0.296
Meters	Heavy Oil (<20 API gr.)	0.0000708	0.03
Meters	Oil/Water	0.0308	0.296
Meters	Oil/Water/Gas	0.0308	0.296
Pressure Relief Valves	Gas	0.0196	0.171
Pressure Relief Valves	NGL	0.0167	0.296
Pressure Relief Valves	Light Oil (>=20 API gr.)	0.0167	0.296
Pressure Relief Valves	Heavy Oil (<20 API gr.)	0.0000708	0.03
Pressure Relief Valves	Oil/Water	0.0308	0.296
Pressure Relief Valves	Oil/Water/Gas	0.0308	0.296

Component Type	Stream Type	EF(lb/hr-comp)	VOC Weight Fraction
Other Relief Valves	Gas	0.0196	0.171
Other Relief Valves	NGL	0.0167	0.296
Other Relief Valves	Light Oil (>=20 API gr.)	0.0167	0.296
Other Relief Valves	Heavy Oil (<20 API gr.)	0.0000708	0.03
Other Relief Valves	Oil/Water	0.0308	0.296
Other Relief Valves	Oil/Water/Gas	0.0308	0.296
Polished Rods	Gas	0.0196	0.171
Polished Rods	NGL	0.0167	0.296
Polished Rods	Light Oil (>=20 API gr.)	0.0167	0.296
Polished Rods	Heavy Oil (<20 API gr.)	0.0000708	0.03
Polished Rods	Oil/Water	0.0308	0.296
Polished Rods	Oil/Water/Gas	0.0308	0.296
Vents	Gas	0.0196	0.171
Vents	NGL	0.0167	0.296
Vents	Light Oil (>=20 API gr.)	0.0167	0.296
Vents	Heavy Oil (<20 API gr.)	0.0000708	0.03
Vents	Oil/Water	0.0308	0.296
Vents	Oil/Water/Gas	0.0308	0.296

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MEMORANDUM

June 22, 2001 (revised July 20, 2001)

TO: Gaylen Drapé STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions Calculations for Glycol Dehydrator Units

Pollutants:
THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)
SO_x = Sulfur oxides

Summary:

At this time, we are unable to interface GRI-GlyCalc with the DBMS. (EPA's preferred method of calculating emissions is to use GRI-GlyCalc.) Instead, we are going to use a rough, back-of-the-envelope approach to estimate emissions. These estimates are going to be very rough approximations. Emissions of VOCs will be based upon an emission factor that was derived from a survey of facilities that was conducted by the Louisiana DEQ in 1991* (data summary provided by David Scalfano). Emissions of THC and H_2S will be extrapolated from some molar glycol affinities (THC:VOC and H_2S:VOC) that were modeled using GRI-GlyCalc.

Uncontrolled Regenerator Emissions::

Calculate uncontrolled VOC emissions for glycol regenerators based on processed throughput as follows.

$$E_{VOC,GR} = EF_{(lb/MMscf)} \times Q$$

where:

$E_{VOC,GR}$	=	Emissions of VOC from the glycol regenerator in pounds per month
EF	=	Emission factor = 6.6 lb VOC/MMscf
Q	=	Processed throughput (MMscf) = *TotalGasThru*

*Louisiana Dept. of Environmental Quality, personal communication, 2001.

In lieu of emission factors for H_2S, methane, and ethane, we are going to make some rough assumptions about the relative affinity of glycol for these species (see Table 1). (Calculations of methane and ethane emissions are done as a mid-step to calculate THC emissions, and calculation of H_2S emissions is done as a mid-step to calculate SO_x emissions.) These estimated affinities are based on some modeled results using GRI-GlyCalc 4.0. Also, we will assume that the average molecular weight of VOC emissions is 90 lb/lb-mol (also based on modeled GRI-GlyCalc 4.0 results).

Table 1. Assumed affinities of glycol to various species.

Species	Molecular Weight (lb/lb·mol)	Affinity of Glycol Type for Species	
		Triethylene Glycol (*GlycolType* = TEG)	Ethylene Glycol (*GlycolType* = EG)
Methane	16	1/400	1/20
Ethane	30	1/100	2/5
H_2S	34	6/5	6/5

Example interpretation: With a TEG regenerator, a molecule of methane in the wet gas is 400 times less likely to be emitted to the atmosphere than would be a VOC molecule in the wet gas.

Calculate uncontrolled glycol regenerator emissions for methane, ethane, and H_2S as follows.

$$E_{X,GR} = E_{VOC,GR} \times A_{G,X} \times \frac{Vol\%_X}{Vol\%_{VOC}} \times \frac{mwt_X}{90\ lb/lb \cdot mol}$$

where:

X = Species (H_2S, methane, or ethane)

$E_{X,GR}$ = Emissions of species X from the glycol regenerator in pounds per month.

G = Glycol type ("TEG" or "EG") = *GlycolType*

$A_{G,X}$ = Affinity of glycol type G for species X (see Table 1).

$Vol\%_X$ = Volume percent of species X in the wet gas = $\begin{cases} ConcNGH2S; \text{if } X = H_2S \\ ConcMethane; \text{if } X = \text{methane} \\ ConcEthane; \text{if } X = \text{ethane} \end{cases}$

$Vol\%_{VOC}$ = Volume percent of VOC in the wet gas = *ConcC3HC* + *ConcC4HC* + *ConcC5HC* + *ConcC6HC* + *ConcC7HC* + *ConcC8plusHC*

mwt_X = Molecular weight of species X in lb/lb·mol.

Calculate uncontrolled glycol regenerator emissions for THC as follows.

$$E_{THC,GR} = E_{VOC,GR} + E_{methane,GR} + E_{ethane,GR}$$

Uncontrolled Flash Tank Emissions:

We will have to use some very roughly approximated ratios in order to estimate emissions for flash tanks (Table 2). These also are based on some GRI-GlyCalc modeling results.

Table 2. Relative ratios of flash tank emissions to glycol regenerator emissions.

Species	Relative Ratio
Methane	1
Ethane	1
VOCs	4.3
H_2S	2.3

Calculate uncontrolled flash tank emissions of VOC, H_2S, methane and ethane as follows.

$$E_{X,FT} = E_{X,GR} \times R_X$$

where:

X = Species (VOC, H_2S, methane, or ethane)

$E_{X,FT}$ = Emissions of species X from the flash tank in pounds per month.

R = Relative ratio of flash tank emissions to glycol regenerator emissions for species X (see Table 2).

Calculate uncontrolled flash tank emissions of THC as follows.

$$E_{THC,FT} = E_{VOC,FT} + E_{methane,FT} + E_{ethane,FT}$$

Total Uncontrolled Emissions:

Calculate total uncontrolled emissions of VOC, THC, and H_2S by summing emissions from the flash tank and the glycol regenerator as follows.

$$E_{X,total} = E_{X,GR} + E_{X,FT}$$

Emissions Controls:

SO_x emissions only arise as a by-product of flaring (which is an emissions control for VOC, THC, and H_2S) from the conversion of H_2S to SO_x in the flare. Thus, if the flare has no emissions controls, then SO_x emissions are zero ($E_{SO_x,uncontrolled} = 0$). Controlled emissions of SO_x are calculated as follows only when *GasesVentOrFlare* = “Flared”.

$$E_{SO_x,control} = E_{H_2S,total} \times \frac{Eff_{flare}}{100\%} \times \frac{64\ \text{lb/lb} \cdot \text{mol}}{34\ \text{lb/lb} \cdot \text{mol}} \times \left(1 - \frac{Eff_{SO_x,other}}{100\%}\right)$$

where:

$E_{SOx,\ control}$ = Emissions of SO_x in pounds per month (when an emissions control in the form of a flare is present)

$E_{H2S,total}$ = Total uncontrolled emissions of H_2S in pounds per month

Eff_{flare} = Combustion efficiency of the flare (assume 95%)

$E_{SOx,\ other}$ = SO_x control efficiency of other control devices installed.

Controlled emissions of VOC and THC are calculated as follows.

$$E_{x,control} = E_{x,total} \times \prod \left(1 - \frac{Eff_i}{100\%}\right)$$

where:

$E_{X,\ control}$ = Controlled emissions of species X in pounds per month

Eff_i = The control efficiency of technology or strategy *i* in percent.

Further specific details are provided below (see “Controlled Emissions” section).

<u>Default Values:</u>

The following default values should be assigned or estimated if the corresponding fields are null. In addition, use the default values for ConcC3HC through ConcC8plusHC if their sum equals zero (*ConcC3HC* + *ConcC4HC* + *ConcC5HC* + *ConcC6HC* + *ConcC7HC* + *ConcC8plusHC* = *0*).

$ConcNGH2S_{default} = 3.18 \times 10^{-4}$

ConcMethane = 90

ConcEthane = 3.8

ConcC3HC = 1.8

ConcC4HC = 1.2

ConcC5HC = 0.6

ConcC6HC = 0.4

ConcC7HC = 0.1

ConcC8plusHC = 0.2

GlycolType = “TEG”

Controlled Emissions:

$$\mathbf{E_{THC,\ control}} = \mathbf{E_{THC,\ unc}} \times (1 - \mathbf{Eff_{THC,VF}} \div 100) \times (1 - \mathbf{Eff_{THC,CT}} \div 100) \times (1 - \mathbf{Eff_{THC,Oth}} \div 100)$$

$$\mathbf{E_{VOC,\ control}} = \mathbf{E_{VOC,\ unc}} \times (1 - \mathbf{Eff_{VOC,VF}} \div 100) \times (1 - \mathbf{Eff_{VOC,CT}} \div 100) \times (1 - \mathbf{Eff_{VOC,Oth}} \div 100)$$

$$\mathbf{E_{SOx,\ control}} = \mathbf{E_{H2S,\ unc}} \times \mathbf{Eff_{H2S,VF}} \div 100 \times 64 \div 34 \times (1 - \mathbf{Eff_{SOx,Oth}} \div 100)$$

IF *GasesVentOrFlare* = “Vented” THEN
$Eff_{THC,VF} = Eff_{VOC,VF} = Eff_{H2S,VF} = 0$

IF *GasesVentOrFlare* = “Flared” THEN
$Eff_{THC,VF} = Eff_{VOC,VF} = 98$
$Eff_{H2S,VF} = 95$

IF *ControlTechnology* = “none” THEN
$Eff_{THC,CT} = Eff_{VOC,CT} = 0$

IF *ControlTechnology* = “VR/C” THEN
$Eff_{THC,CT} = Eff_{VOC,CT} = 80$

IF *OtherControlDevice* = “yes” THEN
$Eff_{THC,Oth} = Eff_{VOC,Oth} = OtherControlEffVOC$
$Eff_{SOx,Oth} = OtherControlEffSOx$
(Note: Treat null values as 0.)

IF *OtherControlDevice* = “no” THEN
$Eff_{THC,Oth} = Eff_{VOC,Oth} = 0$
$Eff_{SOx,Oth} = 0$

New QC Checks:

$$0 < ConcNGH2S_{default} + ConcMethane + ConcEthane + ConcC3HC + ConcC4HC + ConcC5HC + ConcC6HC + ConcC7HC + ConcC8plusHC \leq 100$$

$$0 < ConcC3HC + ConcC4HC + ConcC5HC + ConcC6HC + ConcC7HC + ConcC8plusHC \leq 20$$

$$80 \leq ConcMethane$$

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MEMORANDUM

September 16, 2000

TO: Gaylen Drapé and Suryamani Lingamallu — STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions calculations for loading operations

Pollutants:
THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)

Uncontrolled THC Emissions:

Emissions due to loading operations are generated by the displacement of the vapor space in the receiving cargo hold by liquid product. Vapor losses may include gases that (1) evolved from the residue of the previous cargo, (2) were entrained to the cargo hold during vapor balance operations, or (3) evaporated during the loading of the fresh cargo. For this project, we will assume that ships arrive in uncleaned, ballasted condition and that the previously carried loads were crude oil.

Calculations

For marine loading of crude petroleum and gasoline, *AP-42* recommends the following equation to calculate THC emissions due to loading of fresh cargo.

$$E_{THC} = \left(0.46 + 1.84 \times (0.44 \times P_{VA} - 0.42) \times \frac{mG}{T_b}\right) \times Q \times \frac{42.0\text{gal}}{\text{bbl}} \times 10^{-3}$$

where:
E_{THC} = THC emissions (pounds)
P_{VA} = True vapor pressure of the loaded liquid (psia) = exp[A – (B/T_{LA})]
m = Average molecular weight of vapors (lb/lb-mol) = *TankVOCMolWeight*
G = Vapor growth factor = 1.02
T_b = Liquid Bulk Temperature (°R) = *TankBulkLiqT* + 460
Q = The amount transferred (bbl) = *VolLoaded*

A = Empirical Constant = $12.82 - 0.9672 \times \ln(ReidVP)$
B = Empirical Constant = $7261 - 1216 \times \ln(ReidVP)$
T_{LA} = Daily average liquid surface temperature (°R) = $0.44 \times T_{aa} + (0.56 \times T_b) + (0.0079 \times a \times I)$
T_{aa} = Daily Average Ambient Temperature (°R). (See 2nd row of Table 1.)
a = Tank Paint Solar Absorptance. (See Table 2.)
I = Daily Solar Insulation Factor (Btu/ft^2·day) = 1437 Btu/ft^2·day[A]

Table 1. Daily Average Ambient Temperature, T_{aa}.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
°F	63	64	67	71	77	81	84	84	82	76	71	66
°R	523	524	527	531	537	541	544	544	542	536	531	526

Source: National Climate Data Center (ftp://ftp.ncdc.noaa.gov/pub/datasets/coadsdata/), ComprehensiveOcean-Atmosphere Data Set (COADS). Average monthly temperatures for the period 1980-1992 for Marsden Square 81, 10° Box 241, 2° Box 5537.

Table 2. Tank Paint Solar Absorptance, a.

Paint Color (*TankPaintColor*)	Solar Absorptance by Paint Color and Condition — Paint Condition (*TankPaintCondition*): Good	Poor
Aluminum/Specular	0.39	0.49
Aluminum/Diffuse	0.6	0.68
Grey/Light	0.54	0.63
Grey/Medium	0.68	0.74
Red/Primer	0.89	0.91
White	0.17	0.34

Uncontrolled VOC Emissions:

VOC emissions (E_{VOC}, in pounds) are calculated as a percent of THC emissions.

$$E_{VOC} = \frac{\text{TankVaporWeightPercentVOC}}{100\%} \times E_{THC}$$

Default Values:

The following default values should be assigned or estimated if the corresponding fields are null.

$ReidVP_{default} = 5$

$TankBulkLiqT_{default} = T_{aa}$ (from Table 1, first row) + 6 × a –1

$TankVOCMolWeight_{default} = 50$

$TankVaporWeightPercentVOC_{default} = 85$

[A] Annual average for New Orleans

$FlareEfficiency_{default} = 98$

Controlled Emissions:

$\mathbf{E_{THC,\ control}} = \mathbf{E_{THC,\ unc}} \times (1 - \mathbf{Eff_{THC,VF}} \div 100) \times (1 - \mathbf{Eff_{THC,CT}} \div 100) \times (1 - \mathbf{Eff_{THC,Oth}} \div 100)$

$\mathbf{E_{VOC,\ control}} = \mathbf{E_{VOC,\ unc}} \times (1 - \mathbf{Eff_{VOC,VF}} \div 100) \times (1 - \mathbf{Eff_{VOC,CT}} \div 100) \times (1 - \mathbf{Eff_{VOC,Oth}} \div 100)$

IF *GasesVentOrFlare* = "Vented" THEN
$Eff_{THC,VF} = Eff_{VOC,VF} = 0$

IF *GasesVentOrFlare* = "Flared" THEN
$Eff_{THC,VF} = Eff_{VOC,VF} = FlareEfficiency$

IF *ControlTechnology* = "none" THEN
$Eff_{THC,CT} = Eff_{VOC,CT} = 0$

IF *ControlTechnology* = "Vapor Recovery and/or Condenser (VR/C)" THEN
$Eff_{THC,CT} = Eff_{VOC,CT} = 80$

IF *OtherControlDevice* = "yes" THEN
$Eff_{THC,Oth} = Eff_{VOC,Oth} = OtherControlEffVOC$
(Note: Treat null values as 0.)

IF *OtherControlDevice* = "no" THEN
$Eff_{THC,Oth} = Eff_{VOC,Oth} = 0$

New QC Checks:

No new QC checks will be defined.

MEMORANDUM

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April 26, 2000 (revised April 1, 2002)

TO: Gaylen Drapé and Suryamani Lingamallu STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions Calculations for natural gas engines

Pollutants:

THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)
SO_x = Sulfur oxides (as sulfur dioxide, SO_2)
NO_x = Nitrogen oxides (as nitrogen dioxide, NO_2)
PM_{10} = Particulate matter (with aerodynamic diameter of 10 μm or less)
CO = Carbon monoxide

Summary:

To calculate emissions based on fuel use:

$$E = EF_{(lb/MMscf)} \times 10^{-3} \times U$$

To calculate emissions based on power output:

$$E = EF_{(g/hp\text{-}hr)} \times HP \times t \times \frac{lb}{453.6g}$$

where:

E = Emissions in pounds per month
EF = Emission factor (units are shown in parentheses)
U = Fuel usage (Mscf) = *TotalFuelUsed*
HP = Engine horsepower (hp) = *OperatingHP*
t = Engine operating time (hr/month) = *HrsOperated*

Emission Factors for Natural Gas Engines where *EngineStrokeCycle* = "2-Cycle" and *EngineBurnType* = "Lean"

Pollutant	EF_{fu} (lb/MMscf)	EF_{po} (g/hp-hr)
THC	2100	8.2
VOC	230	0.95
SO_x	$0.179 \times S$	$0.00091 \times S$
NO_x	3100	12
PM_{10}	neg	neg
CO	310	1.2

Emission Factors for Natural Gas Engines where *EngineStrokeCycle* = "4-Cycle" and *EngineBurnType* = "Lean"

Pollutant	EF_{fu} (lb/MMscf)	EF_{po} (g/hp-hr)
THC	1100	4.5
VOC	78	0.31
SO_x	$0.179 \times S$	$0.00085 \times S$
NO_x	3700	15
PM_{10}	10	0.036
CO	310	1.2

Emission Factors for Natural Gas Engines where *EngineStrokeCycle* = "2-Cycle" and *EngineBurnType* = "Clean"

Pollutant	EF_{fu} (lb/MMscf)	EF_{po} (g/hp-hr)
THC	1900	6.4*
VOC	88	0.31
SO_x	$0.179 \times S$	$0.00060 \times S$
NO_x	330	1.1
PM_{10}	29	0.10
CO	350	1.2

Emission Factors for Natural Gas Engines where *EngineStrokeCycle* = "4-Cycle" and *EngineBurnType* = "Clean"

Pollutant	EF_{fu} (lb/MMscf)	EF_{po} (g/hp-hr)
THC	2600	11
VOC	92	0.39
SO_x	$0.179 \times S$	$0.00075 \times S$
NO_x	130	0.54
PM_{10}	17	0.068
CO	530	2.2

Emission Factors** for Natural Gas Engines where *EngineStrokeCycle* = "2-Cycle" and *EngineBurnType* = "Rich"

Pollutant	EF_{fu} (lb/MMscf)	EF_{po} (g/hp-hr)
THC	350	1.5
VOC	29	0.22
SO_x	$0.179 \times S$	$0.00079 \times S$
NO_x	4400	21
PM_{10}	13	0.044
CO	1800	7.3

Emission Factors for Natural Gas Engines where *EngineStrokeCycle* = "4-Cycle" and *EngineBurnType* = "Rich"

Pollutant	EF_{fu} (lb/MMscf)	EF_{po} (g/hp-hr)
THC	350	1.5
VOC	29	0.22
SO_x	$0.179 \times S$	$0.00079 \times S$
NO_x	4400	21
PM_{10}	13	0.044
CO	1800	7.3

The SO_x emission factors vary with fuel sulfur content (ppmv) (S = *FuelH2SContent*).

*I suspect a type-O in the AP-42 draft section, which (if used) would have made this value 6.4×10^{-4}. This should be double-checked later, if possible.

**AP-42 does not provide emission factors for these combinations, therefore, the emission factors for the 4-cycle/rich engine type were applied.

These factors come from AP-42, Draft Section 3.2, Dated June 1997.

If a user-entered value for *TotalFuelUsed* is available or if it can be estimated from the default values (below), then estimate emissions based upon fuel use. Otherwise, if *OperatingHP* and *HrsOperated* are both available, then estimate emissions based upon power output. If none of these conditions are met, don't calculate emissions. Note that you cannot calculate SO_x emissions unless the *FuelH2SContent* is supplied.

Default Values:

The following default values should be assigned or estimated if the corresponding fields are null.

$FuelHeatingValue_{default} = 1050$

$TotalFuelUsed_{default} = FuelUsageRate \times 1/FuelHeatingValue \div 1000 \times OperatingHP \times HrsOperated$

$FuelSulfurContent = 3.18$

Controlled Emissions:

$$\mathbf{E}_{\mathbf{THC,\ control}} = \mathbf{E}_{\mathbf{THC,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{THC,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{VOC,\ control}} = \mathbf{E}_{\mathbf{VOC,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{VOC,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{SOx,\ control}} = \mathbf{E}_{\mathbf{SOx,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{SOx,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{NOx,\ control}} = \mathbf{E}_{\mathbf{NOx,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{NOx,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{PM10,\ control}} = \mathbf{E}_{\mathbf{PM10,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{PM10,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{CO,\ control}} = \mathbf{E}_{\mathbf{CO,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{CO,Oth}} \div 100)$$

IF *OtherControlDevice* = “yes” THEN

$Eff_{THC,Oth} = OtherControlEffVOC$
$Eff_{VOC,Oth} = OtherControlEffVOC$
$Eff_{SOx,Oth} = OtherControlEffSOx$
$Eff_{NOx,Oth} = OtherControlEffNOx$
$Eff_{PM10,Oth} = OtherControlEffPM10$
$Eff_{CO,Oth} = OtherControlEffCO$
(Note: Treat null values as 0.)

IF *OtherControlDevice* = “no” THEN

$Eff_{THC,Oth} = 0$
$Eff_{VOC,Oth} = 0$
$Eff_{SOx,Oth} = 0$
$Eff_{NOx,Oth} = 0$
$Eff_{PM10,Oth} = 0$
$Eff_{CO,Oth} = 0$

New QC Checks:

$0.8 \times TotalFuelUsed \leq FuelUsageRate \times 1/FuelHeatingValue \times 1000 \times OperatingHP \times HrsOperated \leq 1.2 \times TotalFuelUsed$

$FuelUsageRate \leq MaxRatedFuelUsage$

$OperatingHP \leq MaxHP$

MEMORANDUM

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April 26, 2000

TO: Gaylen Drapé and Suryamani Lingamallu   STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions Calculations for Natural Gas Turbines

Pollutants:

THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)
SO_x = Sulfur oxides (as sulfur dioxide, SO_2)
NO_x = Nitrogen oxides (as nitrogen dioxide, NO_2)
PM_{10} = Particulate matter (with aerodynamic diameter of 10 µm or less)
CO = Carbon monoxide

Summary:

To calculate emissions based on fuel use:

$$E = EF_{(\text{lb/MMscf})} \times 10^{-3} \times U$$

To calculate emissions based on power output[3]:

$$E = EF_{(\text{lb/MMscf})} \times \frac{\text{lb/hp-hr}}{125\ \text{lb/MMBtu}} \times \frac{1}{H} \times HP \times t$$

[3] A conversion factor of ~125 was used to convert from lb/MMBtu to lb/hp-hr (see Table 3.1-1 Section 3.1), thus H is included in the equation

where:
E = Emissions in pounds per month
EF = Emission factor (units are shown in parentheses)
U = Fuel usage (Mscf) = *TotalFuelUsed*
H = Fuel heating value (Btu/scf) = *FuelHeatingValue*
HP = Engine horsepower (hp) = *OperatingHP*
t = Engine operating time (hr/month) = *HrsOperated*

Emission Factors for Natural Gas Turbines

Pollutant	EF_{fu} (lb/MMscf)
THC	8.5
VOC	2.8
SO_x	$0.72 \times S$
NO_x	410
PM_{10}	7.4
CO	88

The SO_x emission factor varies with fuel sulfur content (ppmv) (S = *FuelH2SContent*).

These factors come from AP-42, Draft Section 3.1, Dated July 1998.

If a user-entered value for *TotalFuelUsed* is available or if it can be estimated from the default values (below), then estimate emissions based upon fuel use. Otherwise, if *OperatingHP* and *HrsOperated* are both available, then estimate emissions based upon power output. If none of these conditions are met, don't calculate emissions. Note that you cannot calculate SO_x emissions unless the *FuelH2SContent* is supplied.

Default Values:

The following default values should be assigned or estimated if the corresponding fields are null.

$FuelHeatingValue_{default} = 1050$

$TotalFuelUsed_{default} = FuelUsageRate \times 1/FuelHeatingValue \times 1000 \times OperatingHP \times HrsOperated$

FuelSulfurContent = 3.18

Controlled Emissions:

$$\mathbf{E}_{\mathbf{THC,\ control}} = \mathbf{E}_{\mathbf{THC,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{THC,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{VOC,\ control}} = \mathbf{E}_{\mathbf{VOC,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{VOC,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{SOx,\ control}} = \mathbf{E}_{\mathbf{SOx,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{SOx,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{NOx,\ control}} = \mathbf{E}_{\mathbf{NOx,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{NOx,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{PM10,\ control}} = \mathbf{E}_{\mathbf{PM10,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{PM10,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{CO,\ control}} = \mathbf{E}_{\mathbf{CO,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{CO,Oth}} \div 100)$$

IF *OtherControlDevice* = “yes” THEN

$Eff_{THC,Oth}$ = *OtherControlEffVOC*
$Eff_{VOC,Oth}$ = *OtherControlEffVOC*
$Eff_{SOx,Oth}$ = *OtherControlEffSOx*
$Eff_{NOx,Oth}$ = *OtherControlEffNOx*
$Eff_{PM10,Oth}$ = *OtherControlEffPM10*
$Eff_{CO,Oth}$ = *OtherControlEffCO*
(Note: Treat null values as 0.)

IF *OtherControlDevice* = “no” THEN

$Eff_{THC,Oth} = 0$
$Eff_{VOC,Oth} = 0$
$Eff_{SOx,Oth} = 0$
$Eff_{NOx,Oth} = 0$
$Eff_{PM10,Oth} = 0$
$Eff_{CO,Oth} = 0$

New QC Checks:

$0.8 \times TotalFuelUsed \leq FuelUsageRate \times 1/FuelHeatingValue \times 1000 \times OperatingHP \times HrsOperated \leq 1.2 \times TotalFuelUsed$

$FuelUsageRate \leq MaxRatedFuelUsage$

$OperatingHP \leq MaxHP$

MEMORANDUM

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September 14, 2000 (revised February 15, 2002)

TO: Gaylen Drapé and Suryamani Lingamallu — STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions Calculations for Storage Tanks

Pollutants:
THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)

Uncontrolled THC Emissions:

VOC and THC may be lost from storage tanks as a result of flashing, working, and standing losses (L_f, L_w, and L_s). Total emissions = $L_s + L_w + L_f$. I am assuming that all tanks are fixed roof tanks because I really doubt if there are going to be a significant number of offshore floating-roof storage tanks.

Standing Losses. Standing losses (L_s) of THC in pounds are calculated according to the following equation:

$$L_{s,\,THC} = 365 \times V_V \times W_V \times K_E \times K_S$$

where:
V_V = Tank vapor space volume (ft^3) – see discussion below
W_V = Stock vapor density (lb/ft^3) – see discussion below
K_E = Calculated vapor space expansion factor (unitless) – see discussion below
K_S = Calculated vented vapor saturation factor (unitless) – see discussion below
Note: If the tank has a floating roof, standing losses are assumed to be reduced 90%.

Vapor Space Volume, V_V.

For a <u>horizontal, rectangular tank, with a flat roof</u> (where *TankShape* = rectangular, *TankOrientation* = horizontal, and *TankRoofType* = flat)

$$V_V = \mathit{TankShellLength} \times \mathit{TankShellWidth1} \times H_{VO}$$

where:
H_{VO} = Vapor Space Outage (ft) = *TankShellHgt* − *TankAvgLiquidHgt*

For a <u>vertical, rectangular tank with a flat roof</u> (where *TankShape* = rectangular, *TankOrientation* = vertical and *TankRoofType* = flat)

$$V_V = \mathit{TankShellWidth1} \times \mathit{TankShellWidth2} \times H_{VO}$$

where:
H_{VO} = Vapor Space Outage (ft) = *TankShellHgt* − *TankAvgLiquidHgt*

For a <u>horizontal, cylindrical tank</u> (where *TankShape* = rectangular and *TankOrientation* = vertical):

$$V_V = \frac{\pi \times \mathit{TankShellDiam} \times \mathit{TankShellLength} \times H_{VO}}{4 \times 0.785}$$

where:
H_{VO} = Vapor Space Outage (ft) = 0.5 × TankShellDiam (This assumes that the tank is half-full on average.)

For a <u>vertical, cylindrical tank</u> (where *TankShape* = cylindrical and *TankOrientation* = vertical)

$$V_V = \frac{\pi}{4} \times \mathit{TankShellDiam}^2 \times H_{VO}$$

where:
H_{VO} = Vapor space outage (ft) =

$$\begin{cases} \mathit{TankShellHgt\text{-}TankAvgLiquidHgt} + \tfrac{1}{3}\mathit{TankRoofHgt}\text{; if } \mathit{TankRoofType} = \text{"cone"} \\ \mathit{TankShellHgt\text{-}TankAvgLiquidHgt} + \mathit{TankRoofHgt}\left[\tfrac{1}{2} + \tfrac{2}{3}\left(\dfrac{\mathit{TankRoofHgt}}{\mathit{TankShellDiam}}\right)^2\right]\text{; if } \mathit{TankRoofType} = \text{"dome"} \end{cases}$$

Stock vapor density, W_V.

$$W_v = (\mathit{TankVOCMolWeight} \times P_{VA}) \div (10.731 \times T_{LA})$$

where:

T_{LA} = daily average liquid surface temperature (°R) = $0.44 \times T_{aa} + (0.56 \times T_b) + (0.0079 \times a \times I)$
T_{aa} = Daily Average Ambient Temperature (°R). (See 2nd row of Table 1.)
a = Tank Paint Solar Absorptance. (See Table 2.)
T_b = Liquid Bulk Temperature (°R) = *TankBulkLiqT* + 460
I = Daily Solar Insulation Factor ($Btu/ft^2 \cdot day$) = 1437 $Btu/ft^2 \cdot day$[A]
P_{VA} = True Vapor Pressure (psia) = $\exp[A - (B/T_{LA})]$
A = Empirical Constant = $12.82 - 0.9672 \times \ln($*ReidVP*$)$
B = Empirical Constant = $7261 - 1216 \times \ln($*ReidVP*$)$

Table 1. Daily Average Ambient Temperature, T_{aa}.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
°F	63	64	67	71	77	81	84	84	82	76	71	66
°R	523	524	527	531	537	541	544	544	542	536	531	526

Source: National Climate Data Center (ftp://ftp.ncdc.noaa.gov/pub/datasets/coadsdata/), ComprehensiveOcean-Atmosphere Data Set (COADS). Average monthly temperatures for the period 1980-1992 for Marsden Square 81, 10° Box 241, 2° Box 5537.

Table 2. Tank Paint Solar Absorptance, a.

Paint Color (*TankPaintColor*)	Solar Absorptance by Paint Color and Condition — Paint Condition (*TankPaintCondition*): Good	Poor
Aluminum/Specular	0.39	0.49
Aluminum/Diffuse	0.6	0.68
Grey/Light	0.54	0.63
Grey/Medium	0.68	0.74
Red/Primer	0.89	0.91
White	0.17	0.34

Calculated vapor space expansion factor, K_E.

$$K_E = (T_v/T_{LA}) + (P_v - P_b)/(P_a - P_{VA})$$

where:

T_v = Daily Vapor Temperature Range (°R) = $0.72 \times T_a + 0.028 \times a \times I$
T_a = Daily Ambient Temperature Range (°R) = 10°R (assumed)
P_v = Daily Pressure Range (psia)= $0.50 \times B \times Pva \times T_v/T_{LA}^2$

[A] Annual average for New Orleans

P_b = Breather Vent Pressure Setting Range (psig)
= *BreatherVentPressure – BreatherVentVacuum*
P_a = Atmospheric Pressure (psia) = 14.7 psia
Note: If K_E is calculated as above to be a negative value, then set to zero.

Calculated vented vapor saturation factor, K_S.

$$K_s = 1/(1 + 0.053 \times P_{VA} \times H_{VO})$$

Working Losses. Working losses (L_w) of THC in pounds are calculated according to the following equation:

$$L_{w,\,THC} = 0.0010 \times \mathit{TankVOCMolWeight} \times P_{VA} \times \mathit{Throughput} \times K_P \times K_N$$

where:
K_p = Working loss product factor (unitless) = 0.75
K_N = Working loss turnover factor (unitless) = $\begin{cases} 1; \text{for } N \le 36 \\ \frac{180+N}{6N}; \text{for } N > 36 \end{cases}$
N = Number of Turnovers = 5.614 × *Throughput* / V_{LX}
V_{LX} = Tank Maximum Liquid Volume (ft^3) – see discussion below
Note: If the tank has a floating roof, working losses are assumed to be reduced by 90%.

Tank Maximum Liquid Volume, V_{LX}.

For a <u>horizontal, rectangular tank, with a flat roof</u> (where *TankShape* = rectangular, *TankOrientation* = horizontal, and *TankRoofType* = flat)

$$V_{LX} = \mathit{TankShellLength} \times \mathit{TankShellWidth1} \times \mathit{TankShellHgt}$$

<u>For a vertical, rectangular tank with a flat roof</u> (where *TankShape* = rectangular, *TankOrientation* = vertical, and , and *TankRoofType* = flat)

$$V_{LX} = \mathit{TankShellWidth1} \times \mathit{TankShellWidth2} \times \mathit{TankShellHgt}$$

<u>For a horizontal, cylindrical tank</u> (where *TankShape* = rectangular and *TankOrientation* = horizontal):

$$V_{LX} = \frac{\pi}{4} \times \mathit{TankShellDiam}^2 \times \mathit{TankShellLength}$$

<u>For a vertical, cylindrical tank</u> (where *TankShape* = cylindrical and *TankOrientation* = vertical)

$$V_V = \frac{\pi}{4} \times TankShellDiam^2 \times TankShellHgt$$

Flashing Losses. If *HasFlashingLosses* = "no" then flashing losses (L_f) are estimated to be zero. Otherwise, flashing losses of THC in pounds are calculated according to the following equation:

$$L_{f,THC} = GOR \times Throughput \times GD$$

where:
GOR = Gas-to-oil ratio (scf/bbl) – see discussion below
GD = Tank vent hydrocarbon gas density (lb/ft^3) = *MoleFraction* ÷ 100 × *TankVOCMolWeight* ÷ 379

Gas-to-oil ratio, GOR.

$$GOR = C_1 \times UP^{C_2} \times CSG \times \exp\left(\frac{C_3 \times APIGravity}{SeparatorFluidT + 460}\right)$$

where:

C_1 = Vasquez-Beggs Constant = $\begin{cases} 0.0178; \text{if } APIGravity > 30 \\ 0.0362; \text{otherwise} \end{cases}$

UP = Separator pressure (psia) = *LowestSeparatorPressure* + 14.7

C_2 = Vasquez-Beggs Constant = $\begin{cases} 1.187; \text{if } APIGravity > 30 \\ 1.0937; \text{otherwise} \end{cases}$

CSG = Corrected Specific Gravity of Gas
= *SeparatorOilSpecGrvty* × [1.0 + 0.00005912 × *APIGravity* × *SeparatorFluidT* × LOG(UP/114.7)]

C_3 = Vasquez-Beggs Constant = $\begin{cases} 23.934; \text{if } APIGravity > 30 \\ 25.724; \text{otherwise} \end{cases}$

<u>Uncontrolled VOC Emissions:</u>

Emissions of VOC are estimated using speciation profiles from an API publication no. 4683.

$$L_{s,VOC} = L_{s,THC} \times 0.67$$
$$L_{w,VOC} = L_{w,THC} \times 0.67$$
$$L_{f,VOC} = L_{f,THC} \times 0.73$$

Default Values:

The following default values should be assigned or estimated if the corresponding fields are null.

$APIGravity_{default} = 37$

$ReidVP_{default} = -1.699 + 0.179 \times APIGravity$

$BreatherVentPressure_{default} = 0.03$

$BreatherVentVacuum_{default} = -0.03$

$TankBulkLiqT_{default} = \mathrm{T_{aa}}$ (from Table 1, first row) $+ 6 \times \mathrm{a} - 1$

$TankVOCMolWeight_{default} = 50$

$TankVaporWeightPercentVOC_{default} = 85$

$MoleFraction_{default} = 90$

$TankAvgLiquidHgt_{default} = 0.5 \times TankShellHgt$

$FlareEfficiency_{default} = 98$

Controlled Emissions:

$\mathbf{E_{THC,\,control}} = \mathbf{E_{THC,\,unc}} \times (1 - \mathbf{Eff_{THC,VF}} \div 100) \times (1 - \mathbf{Eff_{THC,CT}} \div 100) \times (1 - \mathbf{Eff_{THC,Oth}} \div 100)$

$\mathbf{E_{VOC,\,control}} = \mathbf{E_{VOC,\,unc}} \times (1 - \mathbf{Eff_{VOC,VF}} \div 100) \times (1 - \mathbf{Eff_{VOC,CT}} \div 100) \times (1 - \mathbf{Eff_{VOC,Oth}} \div 100)$

IF *GasesVentOrFlare* = "Vented" THEN
$\mathrm{Eff_{THC,VF}} = \mathrm{Eff_{VOC,VF}} = 0$

IF *GasesVentOrFlare* = "Flared" THEN
$\mathrm{Eff_{THC,VF}} = \mathrm{Eff_{VOC,VF}} = FlareEfficiency$

IF *ControlTechnology* = "none" THEN
$\mathrm{Eff_{THC,CT}} = \mathrm{Eff_{VOC,CT}} = 0$

IF *ControlTechnology* = "Vapor Recovery and/or Condenser (VR/C)" THEN
$\mathrm{Eff_{THC,CT}} = \mathrm{Eff_{VOC,CT}} = 80$

IF *OtherControlDevice* = "yes" THEN
$\mathrm{Eff_{THC,Oth}} = \mathrm{Eff_{VOC,Oth}} = OtherControlEffVOC$
(Note: Treat null values as 0.)

IF *OtherControlDevice* = "no" THEN
$\mathrm{Eff_{THC,Oth}} = \mathrm{Eff_{VOC,Oth}} = 0$

New QC Checks:

Revise *ReidVP* QC check to be: $0.5 \leq \mathit{ReidVP} < 14$

$T_{aa} - 40 \leq \mathit{TankBulkLiqT} \leq T_{aa} + 40$

$0 \leq \mathit{TankAvgLiquidHgt} \leq \mathit{TankShellHgt}$

$\mathit{TankRoofHgt} \leq 0.2 \times \mathit{TankShellHgt}$

MEMORANDUM

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June 1, 2001

TO: Gaylen Drapé — STI Ref. No. 998202

FROM: Dana Coe

SUBJECT: Emissions Calculations for Vents

Pollutants:
THC = Total hydrocarbons (methane plus ethane, C3, C4, …, C8+)
VOC = Volatile organic compounds (or, non-methane, non-ethane hydrocarbons)

Summary:

(Note: For vents, some variables come from the eqVEN table, while others come from the eqVENOCC table. Variables from the eqVENOCC table are denoted with an asterisk, *.)

In addition to miscellaneous sources, vents can receive exhaust streams that are manifolded from other equipment units on the same platform. In order to avoid double counting the emissions from these manifolded equipment units (which are calculated with the methods prescribed in previous memoranda), we will have to subtract their emissions from the total vent gas stream.[4] The first step is to estimate total VOC emissions for a vent (manifolded emissions plus other emissions) according to the following equation.

$$E_{\text{vent, VOC}} = C_{\text{VOC}} \times \frac{10^{-6}}{\text{ppm}} \times \frac{m_{\text{VOC}}}{379.4\text{scf/lb} \cdot \text{mol}} \times 1000 \times \left(V' + \sum_{i=1}^{n} F_i^* \times t_i^* \right)$$

[4] Note for air quality modelers: For air quality modeling purposes, emissions from manifolded units should be treated as having the same exhaust elevation, exit velocity, and exit temperature as the vent to which they are directed.

where:

E	=	Emissions in pounds per month
C_{VOC}	=	Concentration of VOC in the vent gas (ppmv) = *ConcVOC*
m_{VOC}	=	Molecular weight of VOC (lb/lb·mol) = *VOCMolWeight*
V'	=	Non-upset volume of gas vented (Mscf) = *VolVented*
F_i^*	=	Upset vent feed rate for occurrence i (Mscf/hr) = *AvgFeed**
t_i^*	=	Duration of occurrence i = *HrsOperated**

The second step is to determine whether a vent receives manifolded emissions. Vents can receive manifolded emissions amine units, fugitives, loading operations, storage tanks, and glycol dehydrators. Data tables for equipment units of these types, which also are collocated on the same platform as the vent, will need to be examined to determine if the vent receives their emissions. If the following three conditions are true, then a vent is receiving emissions via manifold from another equipment unit of type, "XXX".

- *EqXXX:IsVentedtoLPCollectSystem* = "yes"
- *EqXXX: VentedToID** = "VEN"
- *EqVEN:UserID:Month:Year:CmplxID:StructID:EquipID* = *EqXXX:UserID:MonthYear:CmplxID:StructID:VentedToID***

where:

XXX	=	"AMI", "FUG", "LOA", "STO", or "GLY"
VentedToID*	=	The first 3 characters of the field VentedToID
VentedToID**	=	The remaining characters of VentedToID after the first 3 characters have been truncated.

The third step is to calculate the emissions from miscellaneous sources that are directed to this vent ($E_{misc,VOC}$).

$$E_{misc,VOC} = \begin{cases} D; \text{if } D > 0 \\ 0; \text{if } D \le 0 \end{cases}$$

where:

D	=	$E_{vent,VOC} - E_{man,VOC}$; (pounds per month)
$E_{man,VOC}$	=	The sum of VOC emissions for all equipment units that are manifolded to this vent (pounds per month), if any. If none, $E_{man,VOC} = 0$.

This method to estimate THC emissions is based upon a data analysis that STI performed for the American Petroleum Institute a couple of years ago (Ryan et al., 1998) and my suggested assumption that miscellaneous vent emissions arise mostly from flashing losses[5]. Our data

[5] Flashing losses arise when a large pressure drop occurs and dissolved gases escape from a liquid oil stream, similar to the way that carbon dioxide escapes from an opened can of soda pop. Flashing losses occur when oil is pumped to the surface from deep underground, where it is at immense pressure, and allowed to equilibrate to a lower pressure or atmospheric pressure.

analysis covered emissions data for flashing losses and storage tank working/breathing losses for a set of 103 storage tanks located on exploration and production facilities. The analysis of measured data indicated that, on average, 90 percent (on a molar basis) of flashing emissions were hydrocarbon emissions. In addition, on average, the molar ratio of ethane:methane:VOC was modeled with API software (E&P Tank) to be 17:41:42. We can use this information to estimate emissions of THC and methane.

First, convert miscellaneous VOC emissions to a molar basis as follows:

$$E_{misc,molVOC} = E_{misc,VOC} \div 44 \text{ lb/lb·mol}$$

Then, estimate miscellaneous vented emissions of methane (Me) and ethane (Et) as follows (pounds per month):

$$E_{misc,Me} = E_{misc,molVOC} \times \frac{41}{42} \times 16 \text{ lb/lb·mol}$$

$$E_{misc,Et} = E_{misc,molVOC} \times \frac{17}{42} \times 30 \text{ lb/lb·mol}$$

Finally, estimate miscellaneous vented emissions of THC as follows (pounds per month):

$$E_{misc,THC} = E_{misc,Me} + E_{misc,Et} + E_{misc,VOC}$$

Default Values:

The following default values should be assigned or estimated if the corresponding fields are null.

VOCMolWeight = 44

Controlled Emissions:

Note: For the following equations, E denotes total emissions ($E_{flare} + E_{pilot}$).

$$\mathbf{E}_{\mathbf{THC,\ control}} = \mathbf{E}_{\mathbf{THC,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{THC}} \div 100) \times (1 - \mathbf{Eff}_{\mathbf{THC,Oth}} \div 100)$$
$$\mathbf{E}_{\mathbf{VOC,\ control}} = \mathbf{E}_{\mathbf{VOC,\ uncontrolled}} \times (1 - \mathbf{Eff}_{\mathbf{VOC}} \div 100) \times (1 - \mathbf{Eff}_{\mathbf{THC,Oth}} \div 100)$$

IF *ControlTechnology* = "condenser" THEN
$Eff_{VOC} = 80$
$Eff_{THC} = 80$

IF *ControlTechnology* = "none" THEN
$Eff_{VOC} = 0$
$Eff_{THC} = 0$

IF *OtherControlDevice* = “yes” THEN

$\text{Eff}_{\text{THC,Oth}} = \textit{OtherControlEffVOC}$

$\text{Eff}_{\text{VOC,Oth}} = \textit{OtherControlEffVOC}$

(Note: Treat null values as 0.)

IF *OtherControlDevice* = “no” THEN

$\text{Eff}_{\text{THC,Oth}} = 0$

$\text{Eff}_{\text{VOC,Oth}} = 0$

New QC Check:

$0.8 \times \textit{StackExitVel} \times \pi \div 4 \times (\textit{StackInnerDiam})^2 \div 144 \leq \textit{VolVented} \leq 1.2 \times \textit{StackExitVel} \times \pi \div 4 \times (\textit{StackInnerDiam})^2 \div 144$

References

Ryan P.A., Coe D.L., and Chinkin L.R. (1998) Correlation equations to predict Reid vapor pressure and properties of gaseous emissions for exploration and production facilities. Report prepared for American Petroleum Institute, Washington, DC by Sonoma Technology, Inc., Petaluma, CA, STI-997340-1798-FR, March.

APPENDIX F

DOCUMENTATION AND GUIDE FOR THE DATABASE MANAGEMENT SYSTEM

GS-01-40

Annotated User's Manual

For the Emissions Inventory of Outer Continental Shelf Platform Activities Adjacent to the Breton National Wilderness Area of the Gulf of Mexico

August 17, 2001
(annotated by STI, July 2002)

Prepared for the Minerals Management Service
Under Subcontract to Sonoma Technology, Inc.
Prime Contract Number 01-98-CT-30856

by ENSCO, Inc.
445 Pineda Ct.
Melbourne, Florida 32940

Table of Contents

1 Introduction

As a deliverable to Minerals Management Service (MMS) Contract 01-98-CT-30856, ENSCO, Inc., under subcontract to Sonoma Technology, Inc., developed a Database Management System (DBMS) to construct emissions inventories from oil platform activities adjacent to the Breton National Wilderness Area in the Gulf of Mexico. The DBMS processes data collected by the Breton Offshore Activities Data System (BOADS) survey tool developed by STI, a Visual Basic program allowing offshore operators to report monthly equipment activity emitting primary air pollutants. The BOADS program generates MS-Access files (in *.mdb format) that serve as input to the DBMS. The DBMS performs simple QC functions and creates a database containing the emissions inventory. DBMS specifications included QC validation criteria for the reported activity data as well as emissions calculation algorithms (consistent with EPA standards) of primary pollutant species (see Table 1) for 12 major types of equipment (see Table 2). The DBMS design provides a comprehensive relational table structure containing platform activity data for the 12 equipment categories and pollutant emissions data. Emission factors are stored in separate Oracle tables for easy access and modification by the user.

Section 2 describes the intended audience for this manual, while Section 3 provides the 2-step procedure for creating the emissions inventory. Database table descriptions and entity-relationship diagrams are provided in Sections 4 and 5, respectively.

Table 1: Primary Pollutant Species

Carbon Monoxide (CO)
Nitrogen Oxide (NO_x)
Sulphur Dioxide (SO_2)
Total Suspended Particles (TSP)
Particulate Matter below 10µm in diameter (PM-10)
Total Hydrocarbons (THC)
Volatile Organic Hydrocarbons (VOC)

Table 2: Types of Platform Equipment

Amine Gas Units
Boilers, Heaters, and Burners
Diesel and Gas Engines
Drilling Rigs
Flares
Fugitives
Glycol Dehydrating Units
Loading Operations
Natural Gas Engines
Natural Gas Turbines
Storage Tanks
Vents

2 Intended Audience

This User's Manual provides instructions for an Oracle database administrator, or an experienced database application specialist, to create an emissions inventory. To operate the DBMS, it is necessary that the user be familiar with the PL/SQL language and be able to run script procedures from the operating system command line.

3 Procedure for Creating the Emissions Database

STI Added Note: On the distribution CD in directory 'Oracle Emissions Export' is an export file (& Log) ready for import into you Oracle database. For this export to work do the following:

1. *Create Tablespace 'SNMDATA' 150mb*
2. *Create Tablespace 'SNMINDX' 200mb*
3. *Create a user 'EMISSIONS' with the default Tablespace 'SNMDATA'.*

The export is a user 'EMISSIONS' export only.

The emissions inventory is created via a stored procedure written in PL/SQL to perform batch processing of user data sets. Typically a data set consists of a single user (possibly reporting multiple complexes/structures) for a one-month period. Processing is done in two steps as described below.

Step 1: Retrieve Survey Data files for the Emissions database:

STI Added Note: The procedure for Step 1 is specific only to the STI project. This text should be replaced as appropriate if the DBMS is applied to a new scenario or project. (For example, the ftp site, ftp.sonomatech.com, which is maintained by STI, was set up for use on this project. It is not available for public use.)

- Login to an Unix server
- Connect to the ftp site to receive the *.mdb files, type the following:
  ftp <ftp.sonomatech.com>
  Userid:
  PWD:
  CD mmsgomr
  CD 'subdirectory'
- Download *.mdb files from ftp site subdirectory, type the following:
  prompt (turns off the Interactive mode.)
  bin (to download files as binary)
  mget * (retrieves all the files and downloads)
  mdel * (only when files have been successfully downloaded)
- Place *.mdb files into appropriate survey month folder. (Note: Pay attention to files that are named revision or email messages that point out a certain file is a revision and for which month.)
- Prior to moving the revision file into a specific folder, remove the originally submitted file into the appropriate survey month update folder. (Note: This is for archiving purposes.)

Step 2: Load Individual " mdb" Files to the Emissions Database
(Note: Load one survey month of data at a time into the Oracle temp tables.)
STI Added Note: You can load more than one month at a time into the Oracle temp tables.

- If the Access mdb file is not version 2000, first convert the mdb file.
- For one mdb file at a time, import dblinkqrysprod.mdb as follows:
  - First, select the Tables tab in Access under objects, then new and Import tables. Then choose the above import file to get the linked tables to Oracle. (Note: Prior to retrieving the linked tables must login into the Production database.)
  - Next, select the Queries tab under objects, the File menu option, get external data and Import. Then choose the above import file to get the query objects.
- Execute each dblink query by double clicking.

STI Added Note: A shortcut for the step immediately above and below. The Access macro 'Load all Tables' found in either the dblinkqrysprod.mdb or 'MergedData_QC.mdb' databases will perform all the necessary steps.

- Execute XXEXECQCCHKS query last. (Note: Even though copying data from Access database to Oracle database done manually, all other processes will run automatically for that set of data if this query is executed last.)

STI Added Note: All other processes will not run automatically. The final step is to Execute <PROCEDURE> ***emgnrc.exec_all_load_qc_em*** *via SQL*Plus, which is discussed further below, to complete the process.*

- The following is a list of the Oracle temp tables vs. Access tables:
  - EQAMIORC - eqAMI
  - EQBOIORC - eqBOI
  - EQDIEORC - eqDIE
  - EQDRIORC - eqDRI
  - EQFLA2ORC - eqFLAOCC
  - EQFLAORC - eqFLA
  - EQFUGORC - eqFUG
  - EQGLYORC - eqGLY
  - EQLOAORC - eqLOA
  - EQNGEORC - eqNGE
  - EQNGTORC - eqNGT
  - EQQCORC - eqQC
  - EQSTOORC - eqSTO
  - EQSTORC - Structures
  - EQSVORC - Surveys
  - EQUSRORC - User
  - EQVEN2ORC - eqVENOCC
  - EQVENORC - eqVEN
  - EXEC_QC_CHECKS - (note: data from Surveys is copied.)

- The Oracle database automatically reads information from EXEC_QC_CHECKS table and begins to run QC validations and range checks for each set of survey data for a specific month. All QC related problems are Inserted as records into the QC_SURVEYS table.

- The following is a list of actual Oracle database tables vs. temp tables:
    - Amine_Gas_Units(AMI) - EQAMIORC
    - Boil_Heat_Burners(BOI) - EQBOIORC
    - Diesel_Gas_Engines(DIE) – EQDIEORC
    - Drilling_Rigs(DRI) – EQDRIORC
    - Flares(FLA) – EQFLAORC
    - Flare_Upsets(FLA2) – EQFLA2ORC
    - Fugitives(FUG) – EQFUGORC
    - Glycol_Dehyd_Units(GLY) – EQGLYORC
    - Loading_Operations(LOA) – EQLOAORC
    - Natural_Gas_Engines(NGE) – EQNGEORC
    - Natural_Gas_Turbines(NGT) – EQNGTORC
    - Pollutants(PO) – (note: New table for emission calculations.)
    - QC_Surveys(QC) – EQQCORC
    - Storage_Tanks(STO) – EQSTOORC
    - Structures(ST) – EQSTORC
    - Surveys(SV) – EQSVORC and EQUSRORC loaded into Surveys
    - Vents(VEN) – EQVENORC
    - Vent_Upsets(VEN2) – EQVENOCC

- The following is a list of Oracle support tables for the Emissions database:
    - Em_Log (note: This table keeps track of all the database procedures that have been executed for each survey set of data.)
    - Em_Error_Log (note: Keeps track of file I/O problems/concerns.)
    - Emission_Factors (note: Various constants used to compute emissions for the various equipment types. These factors can be modified by a responsible user which can modify future calculations for the specific equipment type(s).)
    - Fugitive_Factors (note: Emission factors used specifically for the Fugitives table. Separate table was created since this data involved a different format from the Emission_Factors table.)
    - Emissions_Ref_Codes (note: Domain Values are stored in this table.)
    - Exec_QC_Checks (note: This table keeps track of all data that needs to be validated(QC) and when the validation checks are completed, a status of complete is updated to each survey data record.)

- Execute <PROCEDURE> ***emgnrc.exec_all_load_qc_em*** via SQL*Plus. This procedure will check for null status records in the EXEC_QC_CHECKS table. If any null status surveys(i.e. Userid/Month/Year) exist in this table, then the Oracle database automatically begins to copy from the temp tables into the Oracle perm. Tables and also runs QC on each table. When processing is complete for this survey set of data, the check status field in EXEC_QC_CHECKS table is updated to 'C' for complete. A QC report/flat file of data is written to indicate what fields in the various tables did not pass the validation/range tests. Also the emissions calculations for the various equipment types per survey set are computed and stored in the Pollutants table.

  *STI Added Note: The above automatic process creates *.dat files. The Oracle DBA may create, if needed, a data directory by assigning a file directory path to the initialization parameter* 'UTL_FILE_DIR' (*Oracle PL/SQL file I/O directory). To match the above parameter entry, the DBA will need to modify the package body 'emissions.EMGNRC':*

  Source Line & column (8,28) for the drive path
  Source Line & column (9,31) for the file folder path

- Repeat the cycle from opening the next mdb file and follow all the above steps.
- Some mdb files have multiple months of surveys for the same user. In this case just update Exec_QC_Checks and set chk_status = 'X' where the survey record does not match the month which is currently being loaded. There are also cases where multiple mdb files reflect the same survey set of data(i.e. for the same user just spread across two or three mdb files.) In this case, execute all the querys to load data to Oracle for each mdb file except the Surveys, Users and the XX queries. These should only be executed once so that only one record is inserted into the Exec_QC_Checks table.
- At the end of the specific Survey Month, make sure to clear all Oracle temp. tables data to prepare for the Next Survey Month

4 Database Table Definitions

4.1 Amine Gas Sweetening Unit

Table Name: AMINE_GAS_UNITS

Column Names:

1.	EQUIP_ID	VARCHAR2(8)	
2.	EQUIP_TYPE	VARCHAR2(3)	
3.	STATUS	VARCHAR2(1)	
4.	STATUS_EFF_DATE	DATE	
5.	COMMENTS	VARCHAR2(255)	
6.	QC_DATE	DATE	
7.	ST_ID_FK	NUMBER(20)	
8.	HRS_OPERATED	NUMBER(7,3)	Hours
9.	TOTAL_GAS_THRU	NUMBER(7,3)	MMscf
10.	CONC_NGH2S	NUMBER(7,3)	% by volume
11.	CONC_METHANE	NUMBER(7,3)	% by volume
12.	CONC_ETHANE	NUMBER(7,3)	% by volume
13.	CONC_C3HC	NUMBER(7,3)	% by volume
14.	CONC_C4HC	NUMBER(7,3)	% by volume
15.	CONC_C5HC	NUMBER(7,3)	% by volume
16.	CONC_C6HC	NUMBER(7,3)	% by volume
17.	CONC_C7HC	NUMBER(7,3)	% by volume
18.	CONC_C8PLUS_HC	NUMBER(7,3)	% by volume
19.	EMITTED_H2S	NUMBER(7,3)	Uncontrolled % emitted
20.	EMITTED_METHANE	NUMBER(7,3)	Uncontrolled % emitted
21.	EMITTED_ETHANE	NUMBER(7,3)	Uncontrolled % emitted
22.	EMITTED_C3HC	NUMBER(7,3)	Uncontrolled % emitted
23.	EMITTED_C4HC	NUMBER(7,3)	Uncontrolled % emitted
24.	EMITTED_C5HC	NUMBER(7,3)	Uncontrolled % emitted

25.	EMITTED_C6HC	NUMBER(7,3)	Uncontrolled % emitted
26.	EMITTED_C7HC	NUMBER(7,3)	Uncontrolled % emitted
27.	EMITTED_C8PLUS_HC	NUMBER(7,3)	Uncontrolled % emitted
28.	CONTROL_TECH	VARCHAR2(4)	None; Vapor Recovery and/or Condenser (VR/C); Sulfur Recovery (SR); SR + VR/C
29.	CONDENSERT	NUMBER(7,3)	Degrees F
30.	CONDENSERP	NUMBER(8,3)	psia
31.	SRU_RECOVERY_EFF	NUMBER(6,3)	% of S
32.	IS_VENT_TO_LPCSYS	VARCHAR2(1)	
33.	VENTED_TO_ID	VARCHAR2(11)	Equip type & ID of Vent/Flare on same structure (vent/flare record must exist first)
34.	GASES_VENT_FLARE	VARCHAR2(1)	VENT; FLARE
35.	EQUIP_ELEV	NUMBER(7,3)	ft above msl *No Collection System
36.	EXHAUST_OUTLET_HGT	NUMBER(7,3)	ft *No Collection System
37.	EXHAUST_OT_INNER_DIAM	NUMBER(6,3)	inches *No Collection System
38.	EXHAUST_OT_EXITVEL	NUMBER(8,3)	scfh *No Collection System *Vent only
39.	EXHAUST_OT_ANGLE	NUMBER(7,3)	degrees *No Collection System *Vent only
40.	EXHAUST_OUTLETT	NUMBER(7,3)	Deg F *No Collection System *Vent only
41.	FLARE_FEED_RATE	NUMBER(8,3)	scfh *No Collection System *Flare only
42.	FLARE_COMBUSTIONT	NUMBER(8,3)	Deg F *No Collection System *Flare only
43.	FLARE_EFFICIENCY	NUMBER(6,3)	% (default 90%) *No Collection System *Flare Only
44.	OTHER_CNT_DEV	VARCHAR2(1)	
45.	OTHER_CNT_DESC	VARCHAR2(255)	
46.	OTHER_CNT_EFFSOX	NUMBER(6,3)	%
47.	OTHER_CNT_EFFNOX	NUMBER(6,3)	%
48.	OTHER_CNT_EFFCO	NUMBER(6,3)	%
49.	OTHER_CNT_EFFVOC	NUMBER(6,3)	%
50.	OTHER_CNT_EFFPM10	NUMBER(6,3)	%

4.2 Boiler/Heater/Burner

Table Name: BOIL_HEAT_BURNERS

Column names:

1. EQUIP_ID VARCHAR2(8)
2. EQUIP_TYPE VARCHAR2(3)
3. STATUS VARCHAR2(1)
4. STATUS_EFF_DATE DATE
5. COMMENTS VARCHAR2(255)
6. QC_DATE DATE
7. ST_ID_FK NUMBER(20)
8. MAX_RATED_HIRATE NUMBER(7,3) MMbtu/hr
9. HEAT_INPUT_RATE NUMBER(7,3) MMbtu/hr
10. HRS_OPERATED NUMBER(7,3) Hrs
11. FUEL_TYPE VARCHAR2(2) NATURAL GAS; PROCESS GAS; WASTE GAS; WASTE OIL;
12. MAX_RATED_FUEL_USE NUMBER(10,3) scf/hr
13. MAX_RATED_FUEL_USE_OIL NUMBER(9,3) lb/hr
14. FUEL_USAGE_RATE NUMBER(10,3) scf/hr
15. FUEL_USE_RATE_OIL NUMBER(9,3) lb/hr
16. TOTAL_FUEL_USED NUMBER(10,3) Mscf
17. TOTAL_FUEL_USED_OIL NUMBER(10,3) lb
18. FUEL_HEATING_VALUE NUMBER(8,3) btu/scf
19. FUEL_HEATING_VALUE_OIL NUMBER(9,3) btu/lb
20. FUEL_H2S_CONTENT NUMBER(9,4) ppmv
21. FUEL_H2S_CONTENT_OIL NUMBER(5,3) % by mass
22. EMISSION_CONTROLS VARCHAR2(1) NONE; LOW NOX BURNER; FLU GAS RECIRC
23. EQUIP_ELEV NUMBER(7,3) ft above msl
24. EXHAUST_OUTLET_HGT NUMBER(7,3) ft
25. EXHAUST_OT_INNER_DIAM NUMBER(6,3) inches

26.	EXHAUST_OT_EXITVEL	NUMBER(8,3)	ft/s
27.	EXHAUST_OT_EXITT	NUMBER(8,3)	Deg F
28.	EXHAUST_OT_ANGLE	NUMBER(7,3)	degrees
29.	OTHER_CNT_DEV	VARCHAR2(1)	
30.	OTHER_CNT_DESC	VARCHAR2(255)	
31.	OTHER_CNT_EFFSOX	NUMBER(6,3)	%
32.	OTHER_CNT_EFFNOX	NUMBER(6,3)	%
33.	OTHER_CNT_EFFCO	NUMBER(6,3)	%
34.	OTHER_CNT_EFFVOC	NUMBER(6,3)	%
35.	OTHER_CNT_EFFPM10	NUMBER(6,3)	%

4.3 Diesel or Gasoline Engine

Table Name: DIESEL_GAS_ENGINES

Column Names:

1.	EQUIP_ID	VARCHAR2(8)	
2.	EQUIP_TYPE	VARCHAR2(3)	
3.	STATUS	VARCHAR2(1)	
4.	STATUS_EFF_DATE	DATE	
5.	COMMENTS	VARCHAR2(255)	
6.	QC_DATE	DATE	
7.	ST_ID_FK	NUMBER(20)	
8.	MFR	VARCHAR2(50)	
9.	MODEL	VARCHAR2(50)	
10.	FUEL_TYPE	VARCHAR2(2)	DIESEL; GASOLINE; WASTE OIL/SOLVENT
11.	MAX_HP	NUMBER(8,3)	horsepower
12.	OPERATING_HP	NUMBER(8,3)	horsepower
13.	HRS_OPERATED	NUMBER(7,3)	hours
14.	MAX_RATED_FUEL_USE	NUMBER(9,3)	btu/hp-hr

15. FUEL_USAGE_RATE NUMBER(9,3) btu/hp-hr
16. TOTAL_FUEL_USED NUMBER(10,3) gal
17. FUEL_HEATING_VALUE NUMBER(9,3) btu/lb (default 19,300 for Diesel, 20,300 for gasoline)
18. FUEL_SULFUR_CONTENT NUMBER(5,3) % mass
19. EQUIP_ELEV NUMBER(7,3) ft above msl
20. EXHAUST_OUTLET_HGT NUMBER(7,3) ft
21. EXHAUST_OT_INNER_DIAM NUMBER(6,3) inches
22. EXHAUST_OT_EXITVEL NUMBER(8,3) ft/s
23. EXHAUST_OT_EXITT NUMBER(8,3) Deg F
24. EXHAUST_OT_ANGLE NUMBER(7,3) degrees
25. OTHER_CNT_DEV VARCHAR2(1)
26. OTHER_CNT_DESC VARCHAR2(255)
27. OTHER_CNT_EFFSOX NUMBER(6,3) %
28. OTHER_CNT_EFFNOX NUMBER(6,3) %
29. OTHER_CNT_EFFCO NUMBER(6,3) %
30. OTHER_CNT_EFFVOC NUMBER(6,3) %

OTHER_CNT_EFFPM10 NUMBER(6,3) %

4.4 Drilling Rig

Table Name: DRILLING_RIGS

Column Names:

1. EQUIP_ID VARCHAR2(8)
2. EQUIP_TYPE VARCHAR2(3)
3. STATUS VARCHAR2(1)
4. STATUS_EFF_DATE DATE
5. COMMENTS VARCHAR2(255)
6. QC_DATE DATE
7. ST_ID_FK NUMBER(20)

8. HRS_OPERATED NUMBER(6,3) hours
9. DIESEL_USAGE NUMBER(9,3) Total Diesel Fuel Usage (gal)
10. GAS_USAGE NUMBER(9,3) Total Gasoline Fuel Usage (gal)
11. NG_USAGE NUMBER(9,3) Total Natural Gas Fuel Usage (Mscf)
12. OTHER_CNT_DEV VARCHAR2(1)
13. OTHER_CNT_DESC VARCHAR2(255)
14. OTHER_CNT_EFFSOX NUMBER(6,3) %
15. OTHER_CNT_EFFNOX NUMBER(6,3) %
16. OTHER_CNT_EFFCO NUMBER(6,3) %
17. OTHER_CNT_EFFVOC NUMBER(6,3) %
18. OTHER_CNT_EFFPM10 NUMBER(6,3) %

4.5 Flares

Table Name: FLARES

Column Names:

1. EQUIP_ID VARCHAR2(8)
2. EQUIP_TYPE VARCHAR2(3)
3. STATUS VARCHAR2(1)
4. STATUS_EFF_DATE DATE
5. COMMENTS VARCHAR2(255)
6. QC_DATE DATE
7. ST_ID_FK NUMBER(20)
8. STACK_OUTLET_ELEV NUMBER(7,3) ft above msl
9. STACK_ANGLE NUMBER(3) degrees; 0=vert, 90=horiz; 180=down (range 1-180)
10. STACK_INNER_DIAM NUMBER(6,3) inches
11. STACK_EXIT_VEL NUMBER(8,3) ft/s
12. STACK_EXITT NUMBER(8,3) Deg F
13. NUM_FLARE_OCCUR NUMBER(4,0) Number of upset flare occurances. For each, track the start date, duration (hrs), peak flare feed rate (Mscf/hr).

14.	HRS_OPERATED	NUMBER(7,3)	hours
15.	VOL_FLARED	NUMBER(9,3)	Mscf
16.	FLARE_EFFICIENCY	NUMBER(6,3)	%
17.	CONC_H2S	NUMBER(11,4)	ppmv
18.	FLARE_SMOKE	VARCHAR2(1)	NONE; LIGHT; MEDIUM; HEAVY
19.	HAS_CONT_FLARE_PILOT	VARCHAR2(1)	
20.	PILOT_FUEL_FEED_RATE	NUMBER(7,3)	Mscf
21.	OTHER_CNT_DEV	VARCHAR2(1)	
22.	OTHER_CNT_DESC	VARCHAR2(255)	
23.	OTHER_CNT_EFFSOX	NUMBER(6,3)	%
24.	OTHER_CNT_EFFNOX	NUMBER(6,3)	%
25.	OTHER_CNT_EFFCO	NUMBER(6,3)	%
26.	OTHER_CNT_EFFVOC	NUMBER(6,3)	%
27.	OTHER_CNT_EFFPM10	NUMBER(6,3)	%

4.6 Flare Upsets

Table Name: FLARE_UPSETS

Column Names:

1.	TIME_STAMP	DATE	Date and time
2.	HRS_OPERATED	NUMBER(7,3)	hours
3.	AVG_FEED	NUMBER(9,3)	Mscf/hr
4.	CONC_H2S	NUMBER(11,4)	ppmv
5.	COMB_TEMP	NUMBER(9,3)	Deg F
6.	COMMENTS	VARCHAR2(255)	
7.	ST_ID_FK	NUMBER(20)	
8.	EQUIP_ID_FK	VARCHAR2(8)	
9.	EQUIP_TYPE_FK	VARCHAR2(3)	

4.7 Fugitives

Table Name: FUGITIVES

Column Names:

1. EQUIP_ID VARCHAR2(8)
2. EQUIP_TYPE VARCHAR2(3)
3. STATUS VARCHAR2(1)
4. STATUS_EFF_DATE DATE
5. COMMENTS VARCHAR2(255)
6. QC_DATE DATE
7. ST_ID_FK NUMBER(20)
8. FACILITY_SIZE VARCHAR2(1) SMALL (<=1000 components); MEDIUM (1000-10,000 components); LARGE (>10,000 components)
9. STREAM_TYPE VARCHAR2(2) Light Oil (>=20 APIG); Heavy Oil (<20 APIG); OIL/WATER; OIL/WATER/GAS; GAS; NGL
10. VALVES NUMBER(8,3) Count
11. PUMP_SEALS NUMBER(7,3) Count
12. CONNECTORS NUMBER(8,3) Count
13. FLANGES NUMBER(8,3) Count
14. OPEN_ENDED_LINES NUMBER(7,3) Count
15. COMPRESSORS NUMBER(7,3) Count
16. DIAPHRAGMS NUMBER(8,3) Count
17. DRAINS NUMBER(7,3) Count
18. DUMP_ARMS NUMBER(8,3) Count
19. HATCHES NUMBER(7,3) Count
20. INSTRUMENTS NUMBER(8,3) Count
21. METERS NUMBER(7,3) Count
22. PRESSURE_RELIEF_VALVES NUMBER(8,3) Count
23. POLISHED_RODS NUMBER(7,3) Count
24. OTHER_RELIEF_VALVES NUMBER(7,3) Count
25. VENTS NUMBER(7,3) Count

26. IS_VENT_TO_LPCSYS VARCHAR2(1)

27. VENTED_TO_ID VARCHAR2(11) Equip type & ID of Vent/Flare on same structure (vent/flare record must exist first)

28. GASES_VENT_FLARE VARCHAR2(1) VENTED; FLARED

29. EQUIP_ELEV NUMBER(7,3) ft above msl *No Collection System

30. EXHAUST_OUTLET_HGT NUMBER(7,3) ft *No Collection System

31. EXHAUST_OT_INNER_DIAM NUMBER(6,3) inches *No Collection System

32. EXHAUST_OT_EXITVEL NUMBER(8,3) scfh *No Collection System *Vent only

33. EXHAUST_OT_ANGLE NUMBER(7,3) degrees *No Collection System *Vent only

34. EXHAUST_OT_EXITT NUMBER(8,3) Deg F *No Collection System *Vent only

35. FLARE_FEED_RATE NUMBER(9,3) scfh *No Collection System *Flare only

36. FLARE_COMBUSTIONT NUMBER(8,3) Deg F *No Collection System *Flare only

37. FLARE_EFFICIENCY NUMBER(6,3) % (default 90%) *No Collection System *Flare Only

38. OTHER_CNT_DEV VARCHAR2(1)

39. OTHER_CNT_DESC VARCHAR2(255)

40. OTHER_CNT_EFFSOX NUMBER(6,3) %

41. OTHER_CNT_EFFNOX NUMBER(6,3) %

42. OTHER_CNT_EFFCO NUMBER(6,3) %

43. OTHER_CNT_EFFVOC NUMBER(6,3) %

44. OTHER_CNT_EFFPM10 NUMBER(6,3) %

45. WEIGHT_PER_VOC NUMBER(7,3) %

4.8 Fugitive Factors

Table Name: FUGITIVE_FACTORS

Column Names:

1. COMPONENT_TYPE VARCHAR2(30)

2. STREAM_TYPE VARCHAR2(30)

3. EF_COMP NUMBER()

4. WT_FRAC_VOC NUMBER()

4.9 Glycol Dehydrator Unit

Table Name: GLYCOL_DEHYD_UNITS

Column Names:

1.	EQUIP_ID	VARCHAR2(8)	
2.	EQUIP_TYPE	VARCHAR2(3)	
3.	STATUS	VARCHAR2(1)	
4.	STATUS_EFF_DATE	DATE	
5.	COMMENTS	VARCHAR2(255)	
6.	QC_DATE	DATE	
7.	ST_ID_FK	NUMBER(20)	
8.	HRS_OPERATED	NUMBER(7,3)	hours
9.	TOTAL_GAS_THRU	NUMBER(9,3)	Mscf
10.	CONC_NGH2S	NUMBER(7,3)	ppmv
11.	CONC_METHANE	NUMBER(7,3)	% by volume
12.	CONC_ETHANE	NUMBER(7,3)	% by volume
13.	CONC_C3HC	NUMBER(7,3)	% by volume
14.	CONC_C4HC	NUMBER(7,3)	% by volume
15.	CONC_C5HC	NUMBER(7,3)	% by volume
16.	CONC_C6HC	NUMBER(7,3)	% by volume
17.	CONC_C7HC	NUMBER(7,3)	% by volume
18.	CONC_C8PLUS_HC	NUMBER(7,3)	% by volume
19.	GLYCOL_TYPE	VARCHAR2(1)	TEG; EG
20.	RECIRC_RATE	NUMBER(6,3)	gal/min
21.	LEAN_GLY_WATER_CONT	NUMBER(9,3)	% by weight
22.	WET_GAS_WATER_CONT	NUMBER(8,3)	lb/MMscf
23.	DRY_GAS_WATER_CONT	NUMBER(7,3)	lb/MMscf (TEG units only)
24.	WET_GAST	NUMBER(7,3)	Deg F
25.	WET_GASP	NUMBER(8,3)	psig

26. COLD_SEPARATORT NUMBER(8,3) Deg F

27. COLD_SEPARATORP NUMBER(8,3) psig

28. GLYCOL_PUMP_TYPE VARCHAR2(1) ELECTRIC; GAS

29. USE_FLASH_TANK VARCHAR2(1) YES/No

30. FLASH_TANKT NUMBER(7,3) Deg F

31. FLASH_TANKP NUMBER(8,3) psig

32. STRIPPING_GAS VARCHAR2(2) NONE; DRY GAS; FLASH GAS; NITROGEN

33. STRIPPING_GAS_FLOW_RT NUMBER(9,3) scfm

34. CONTROL_TECH VARCHAR2(4) Vapor Recovery and/or Condenser (VR/C); None

35. CONDENSERT NUMBER(7,3) Deg F

36. CONDENSERP NUMBER(7,3) psia

37. IS_VENT_TO_LPCSYS VARCHAR2(1) yes/no

38. VENTED_TO_ID VARCHAR2(11) Equip type & ID of Vent/Flare on same structure (vent/flare record must exist first)

39. GASES_VENT_FLARE VARCHAR2(1) VENTED; FLARED

40. EQUIP_ELEV NUMBER(7,3) ft above msl *No Collection System

41. EXHAUST_OUTLET_HGT NUMBER(7,3) ft *No Collection System

42. EXHAUST_OT_INNER_DIAM NUMBER(6,3) inches *No Collection System

43. EXHAUST_OT_EXITVEL NUMBER(8,3) scfh *No Collection System *Vent only

44. EXHAUST_OT_ANGLE NUMBER(7,3) degrees *No Collection System *Vent only

45. EXHAUST_OT_EXITT NUMBER(8,3) Deg F *No Collection System *Vent only

46. FLARE_FEED_RATE NUMBER(9,3) scfh *No Collection System *Flare only

47. FLARE_COMBUSTIONT NUMBER(8,3) Deg F *No Collection System *Flare only

48. FLARE_EFFICIENCY NUMBER(6,3) % (default 90%) *No Collection System *Flare Only

49. OTHER_CNT_DEV VARCHAR2(1)

50. OTHER_CNT_DESC VARCHAR2(255)

51. OTHER_CNT_EFFSOX NUMBER(6,3) %

52. OTHER_CNT_EFFNOX NUMBER(6,3) %

53. OTHER_CNT_EFFCO NUMBER(6,3) %

54.	OTHER_CNT_EFFVOC	NUMBER(6,3)	%
55.	OTHER_CNT_EFFPM10	NUMBER(6,3)	%

4.10 Loading Operations

Table Name: LOADING_OPERATIONS

Column Names:

1.	EQUIP_ID	VARCHAR2(8)	
2.	EQUIP_TYPE	VARCHAR2(3)	
3.	STATUS	VARCHAR2(1)	
4.	STATUS_EFF_DATE	DATE	
5.	COMMENTS	VARCHAR2(255)	
6.	QC_DATE	DATE	
7.	ST_ID_FK	NUMBER(20)	
8.	VOL_LOADED	NUMBER(11,3)	bbl
9.	TANK_PAINT_COLOR	VARCHAR2(2)	ALUMINUM/SPECULAR; ALUMINUM/DIFFUSE; GREY/LIGHT; GREY/MED; RED/PRIMER; WHITE/NA
10.	TANK_PAINT_CND	VARCHAR2(1)	GOOD; POOR
11.	TANK_BULK_LIQT	NUMBER(7,3)	Deg F
12.	REID_VP	NUMBER(6,3)	psia
13.	TANK_VOC_MOLWGT	NUMBER(7,3)	lb/lb-mol (defualt 50)
14.	TANK_VAPWGT_PVOC	NUMBER(7,3)	% (default 85%, range 55-100)
15.	CONTROL_TECH	VARCHAR2(4)	Vapor Recovery and/or Condenser (VR/C); None
16.	CONDENSERT	NUMBER(7,3)	Deg F
17.	CONDENSERP	NUMBER(8,3)	psia
18.	IS_VENT_TO_LPCSYS	VARCHAR2(1)	yes/no
19.	VENTED_TO_ID (vent/flare record must exist first)	VARCHAR2(11)	Equip type & ID of Vent/Flare on same structure
20.	GASES_VENT_FLARE	VARCHAR2(1)	VENT; FLARE
21.	EQUIP_ELEV	NUMBER(7,3)	ft above msl *No Collection System
22.	EXHAUST_OUTLET_HGT	NUMBER(7,3)	ft *No Collection System

23.	EXHAUST_OT_INNER_DIAM	NUMBER(6,3)	inches *No Collection System
24.	EXHAUST_OT_EXITVEL	NUMBER(8,3)	scfh *No Collection System *Vent only
25.	EXHAUST_OT_ANGLE	NUMBER(7,3)	degrees *No Collection System *Vent only
26.	EXHAUST_OT_EXITT	NUMBER(8,3)	Deg F *No Collection System *Vent only
27.	FLARE_FEED_RATE	NUMBER(9,3)	scfh *No Collection System *Flare only
28.	FLARE_COMBUSTIONT	NUMBER(8,3)	Deg F *No Collection System *Flare only
29.	FLARE_EFFICIENCY	NUMBER(6,3)	% (default 90%) *No Collection System *Flare Only
30.	OTHER_CNT_DEV	VARCHAR2(1)	
31.	OTHER_CNT_DESC	VARCHAR2(255)	
32.	OTHER_CNT_EFFSOX	NUMBER(6,3)	%
33.	OTHER_CNT_EFFNOX	NUMBER(6,3)	%
34.	OTHER_CNT_EFFCO	NUMBER(6,3)	%
35.	OTHER_CNT_EFFVOC	NUMBER(6,3)	%
36.	OTHER_CNT_EFFPM10	NUMBER(6,3)	%

4.11 Natural Gas Engine

Table Name: NATURAL_GAS_ENGINES

Column Names:

1.	EQUIP_ID	VARCHAR2(8)	
2.	EQUIP_TYPE	VARCHAR2(3)	
3.	STATUS	VARCHAR2(1)	
4.	STATUS_EFF_DATE	DATE	
5.	COMMENTS	VARCHAR2(255)	
6.	QC_DATE	DATE	
7.	ST_ID_FK	NUMBER(20)	
8.	MFR	VARCHAR2(50)	
9.	MODEL	VARCHAR2(50)	
10.	MAX_HP	NUMBER(9,3)	horsepower

11. OPERATING_HP NUMBER(9,3) horsepower
12. ENGINE_STROKE_CYCLE NUMBER(1) "2-Cycle" Or "4-Cycle" Or Is Null
13. ENGINE_BURN_TYPE VARCHAR2(1) LEAN; CLEAN; RICH
14. HRS_OPERATED NUMBER(7,3) hours
15. MAX_RATED_FUEL_USE NUMBER(8,3) btu/hp-hr
16. FUEL_USAGE_RATE NUMBER(8,3) btu/hp-hr
17. TOTAL_FUEL_USED NUMBER(10,3) Mscf
18. FUEL_HEATING_VALUE NUMBER(8,3) Btu/scf (Default 1050)
19. FUEL_H2S_CONTENT NUMBER(10,4) ppmv
20. EQUIP_ELEV NUMBER(7,3) ft above msl
21. EXHAUST_OUTLET_HGT NUMBER(7,3) ft
22. EXHAUST_OT_INNER_DIAM NUMBER(6,3) inches
23. EXHAUST_OT_EXITVEL NUMBER(8,3) ft/s
24. EXHAUST_OT_EXITT NUMBER(8,3) Deg F
25. EXHAUST_OT_ANGLE NUMBER(7,3) degrees
26. OTHER_CNT_DEV VARCHAR2(1)
27. OTHER_CNT_DESC VARCHAR2(255)
28. OTHER_CNT_EFFSOX NUMBER(6,3) %
29. OTHER_CNT_EFFNOX NUMBER(6,3) %
30. OTHER_CNT_EFFCO NUMBER(6,3) %
31. OTHER_CNT_EFFVOC NUMBER(6,3) %
32. OTHER_CNT_EFFPM10 NUMBER(6,3) %

4.12 Natural Gas Turbine

Table Name: NATURAL_GAS_TURBINES

Column Names:

1. EQUIP_ID VARCHAR2(8)
2. EQUIP_TYPE VARCHAR2(3)
3. STATUS VARCHAR2(1)

4.	STATUS_EFF_DATE	DATE	
5.	COMMENTS	VARCHAR2(255)	
6.	QC_DATE	DATE	
7.	ST_ID_FK	NUMBER(20)	
8.	MFR	VARCHAR2(50)	
9.	MODEL	VARCHAR2(50)	
10.	MAX_HP	NUMBER(9,3)	horsepower
11.	OPERATING_HP	NUMBER(9,3)	horsepower
12.	PURPOSE	VARCHAR2(2)	ELECTRICITY GENERATION; PRODUCT PRESSURIZATION;
13.	HRS_OPERATED	NUMBER(7,3)	hours
14.	MAX_RATED_FUEL_USE	NUMBER(8,3)	btu/hp-hr
15.	FUEL_USAGE_RATE	NUMBER(8,3)	btu/hp-hr
16.	TOTAL_FUEL_USED	NUMBER(10,3)	Mscf
17.	FUEL_HEATING_VALUE	NUMBER(8,3)	Btu/scf (Default 1050)
18.	FUEL_H2S_CONTENT	NUMBER(10,4)	ppmv
19.	EQUIP_ELEV	NUMBER(7,3)	ft above msl
20.	EXHAUST_OUTLET_HGT		NUMBER(7,3) ft
21.	EXHAUST_OT_INNER_DIAM	NUMBER(6,3)	inches
22.	EXHAUST_OT_EXITVEL	NUMBER(8,3)	ft/s
23.	EXHAUST_OT_EXITT	NUMBER(8,3)	Deg F
24.	EXHAUST_OT_ANGLE	NUMBER(7,3)	degrees
25.	OTHER_CNT_DEV	VARCHAR2(1)	
26.	OTHER_CNT_DESC	VARCHAR2(255)	
27.	OTHER_CNT_EFFSOX	NUMBER(6,3)	%
28.	OTHER_CNT_EFFNOX	NUMBER(6,3)	%
29.	OTHER_CNT_EFFCO	NUMBER(6,3)	%
30.	OTHER_CNT_EFFVOC	NUMBER(6,3)	%
31.	OTHER_CNT_EFFPM10	NUMBER(6,3)	%

4.13 Pollutants

Table Name: POLLUTANTS

Column Names:

1. PO_ID NUMBER(20,0) Unique Identifier or sequence for each record in the pollutants table.

2. PO_TYPE VARCHAR(4) A specific type of pollutant being computed (CO, NOx, SOx, VOC, PM10, THC etc.)

3. PO_DEFAULT_COMP VARCHAR2(1) A flag to indicate (Y)es/(N)o that this specific pollutant was computed using default values.

4. AIR_POLLUTANT NUMBER(20,4) Emission calculation value for a specific pollutant already defined.

5. EMISSION_TYPE VARCHAR2(2) Emission calculation is of type Controlled or Uncontrolled.

6. PO_CALC_TYPE VARCHAR2(2) Emission calculation based on fuel usage.

7. ST_ID_FK NUMBER(20)

8. EQUIP_ID_FK VARCHAR2(8)

9. EQUIP_TYPE_FK VARCHAR2(3)

4.14 Storage Tank

Table Name: STORAGE_TANKS

Column Names:

1.	EQUIP_ID	VARCHAR2(8)	
2.	EQUIP_TYPE	VARCHAR2(3)	
3.	STATUS	VARCHAR2(1)	
4.	STATUS_EFF_DATE	DATE	
5.	COMMENTS	VARCHAR2(255)	
6.	QC_DATE	DATE	
7.	ST_ID_FK	NUMBER(20)	
8.	TANK_SHAPE	VARCHAR2(1)	CYLINDRICAL; RECTANGULAR
9.	TANK_ORIENTATION	VARCHAR2(1)	HORIZONTAL; VERTICAL (default vertical)
10.	TANK_SHELL_DIAM	NUMBER(6,3)	ft *cylindrical
11.	TANK_SHELL_HGT	NUMBER(6,3)	ft *vertical
12.	TANK_SHELL_LENGTH	NUMBER(6,3)	ft *horizontal
13.	TANK_SHELL_WIDTH1	NUMBER(6,3)	ft *rectangular
14.	TANK_SHELL_WIDTH2	NUMBER(6,3)	ft *rectangular
15.	FIXED_ROOF	VARCHAR2(1)	Fixed = yes, floating - no
16.	TANK_ROOF_TYPE	VARCHAR2(1)	CONE, DOME, FLAT, PEAKED
17.	TANK_ROOF_HGT	NUMBER(6,3)	ft
18.	TANK_PAINT_COLOR	VARCHAR2(2)	ALUMINUM/SPECULAR; ALUMINUM/DIFFUSE; GREY/LIGHT; GREY/MED; RED/PRIMER; WHITE/NA
19.	TANK_PAINT_CND	VARCHAR2(1)	GOOD; POOR
20.	BREATH_VENT_PRES	NUMBER(6,3)	psig
21.	BREATH_VENT_VAC	NUMBER(6,3)	psig
22.	TANK_AVG_LIQ_HGT	NUMBER(6,3)	ft
23.	TANK_BULK_LIQT	NUMBER(7,3)	Deg F
24.	PRODUCT_TYPE	VARCHAR2(2)	CRUDE; CONDENSATE
25.	API_GRAVITY	NUMBER(6,3)	Product API Gravity, measured in oAPI

26.	REID_VP	NUMBER(6,3)	Product Reid Vapor Pressure, measured in psia
27.	THROUGH_PUT	NUMBER(11,3)	bbl
28.	HAS_FLASH_LOSS	VARCHAR2(1)	yes/no
29.	TANK_VOC_MOLWGT	NUMBER(7,3)	lb/lb-mol (defualt 50)
30.	TANK_VAPWGT_PVOC	NUMBER(6,3)	% (default 85%, range 55-100)
31.	MOLE_FRACTION	NUMBER(7,3)	Mole Fraction THC in vented Gas; between 0-1 *if Flashing Losses
32.	LOW_SEP_PRESSURE	NUMBER(6,3)	Separator Pressure, measured in psig *if Flashing Losses
33.	SEPARATOR_FLUIDT	NUMBER(7,3)	Separator Fluid Temp, measured in F *if Flashing Losses
34.	SEP_OIL_SPEC_GRVTY	NUMBER(5,3)	Separator Oil Specific Gravity, *if Flashing Losses
35.	SEP_OIL_H2S_CONTENT	NUMBER(5,3)	mol% H2S
36.	SEP_OIL_O2_CONTENT	NUMBER(6,3)	mol% oxygen
37.	SEP_OIL_CO2_CONTENT	NUMBER(6,3)	mol% carbon dioxide
38.	SEP_OIL_N2_CONTENT	NUMBER(6,3)	mol% nitrogen
39.	SEP_OIL_C1_CONTENT	NUMBER(6,3)	mol% methane
40.	SEP_OIL_C2_CONTENT	NUMBER(6,3)	mol% ethane
41.	SEP_OIL_C3_CONTENT	NUMBER(6,3)	mol% propane
42.	SEP_OIL_IC4_CONTENT	NUMBER(6,3)	mol% isobutane
43.	SEP_OIL_NC4_CONTENT	NUMBER(6,3)	mol% n-butane
44.	SEP_OIL_IC5_CONTENT	NUMBER(6,3)	mol% isopentane
45.	SEP_OIL_NC5_CONTENT	NUMBER(6,3)	mol% n-pentane
46.	SEP_OIL_C6_CONTENT	NUMBER(6,3)	mol% C6 hydrocarbons
47.	SEP_OIL_C7_CONTENT	NUMBER(6,3)	mol% C7 hydrocarbons
48.	SEP_OIL_C8_CONTENT	NUMBER(6,3)	mol% C8 hydrocarbons
49.	SEP_OIL_C9_CONTENT	NUMBER(6,3)	mol% C9 hydrocarbons
50.	SEP_OIL_C10_PLCONT	NUMBER(6,3)	mol% C10 hydrocarbons
51.	CONTROL_TECH	VARCHAR2(4)	Vapor Recovery and/or Condenser (VR/C); None
52.	CONDENSERT	NUMBER(7,3)	Deg F

53. CONDENSERP NUMBER(7,3) psia
54. IS_VENT_TO_LPCSYS VARCHAR2(1) yes/no
55. VENTED_TO_ID VARCHAR2(15) Equip type & ID of Vent/Flare on same structure
    (vent/flare record must exist first)
56. GASES_VENT_FLARE VARCHAR2(1) VENTED; FLARED
57. EQUIP_ELEV VARCHAR2(7) ft above msl *No Collection System
58. EXHAUST_OUTLET_HGT NUMBER(7,3) ft *No Collection System
59. EXHAUST_OT_INNER_DIAM NUMBER(6,3) inches *No Collection
    System
60. EXHAUST_OT_EXITVEL NUMBER(8,3) scfh *No Collection System *Vent only
61. EXHAUST_OT_ANGLE NUMBER(7,3) degrees *No Collection System *Vent only
62. EXHAUST_OT_EXITT NUMBER(8,3) Deg F *No Collection System *Vent only
63. FLARE_FEED_RATE NUMBER(9,3) scfh *No Collection System *Flare only
64. FLARE_COMBUSTIONT NUMBER(8,3) Deg F *No Collection System *Flare only
65. FLARE_EFFICIENCY NUMBER(6,3) % (default 90%) *No Collection System *Flare
    Only
66. OTHER_CNT_DEV VARCHAR2(1)
67. OTHER_CNT_DESC VARCHAR2(255)
68. OTHER_CNT_EFFSOX NUMBER(6,3) %
69. OTHER_CNT_EFFNOX NUMBER(6,3) %
70. OTHER_CNT_EFFCO NUMBER(6,3) %
71. OTHER_CNT_EFFVOC NUMBER(6,3) %
72. OTHER_CNT_EFFPM10 NUMBER(6,3) %

4.15 Structure Information

Table name: STRUCTURES

Column Names:

1. ST_ID NUMBER(20)
2. COMPLEX_ID_NUM VARCHAR2(7)
3. STRUCTURE_NUMBER VARCHAR2(2)

4.	AREA	VARCHAR2(50)
5.	BLOCK	VARCHAR2(50)
6.	NAME	VARCHAR2(50)
7.	LONGITUDE	NUMBER(13,8)
8.	LATITUDE	NUMBER(12,8)
9.	DIST_TO_SHORE	NUMBER(3,0)
10.	LEASE_NUMBER	VARCHAR2(25)
11.	CONTACT	VARCHAR2(25)
12.	PHONE	VARCHAR2(25)
13.	EMAIL	VARCHAR2(50)
14.	PROD_OIL	NUMBER(11,3)
15.	PROD_NG	NUMBER(9,3)
16.	PROD_NGH2S	NUMBER(11,4)
17.	THRU_OIL	NUMBER(11,3)
18.	THRU_NG	NUMBER(12,3)
19.	THRU_NGH2S	NUMBER(11,4)
20.	ADD_THRU_OIL	NUMBER(11,3)
21.	OIL_PROC_CMPLXID	VARCHAR2(50)
22.	OIL_PROC_STRUCTID	VARCHAR2(50)
23.	OIL_PROC_STRTYPE	VARCHAR2(3)
24.	TOTAL_FUEL_USE_NG	NUMBER(11,3)
25.	TOTAL_FUEL_USE_GAS	NUMBER(11,3)
26.	TOTAL_FUEL_USE_DIE	NUMBER(10,3)
27.	STATUS	VARCHAR2(1)
28.	STATUS_EFF_DATE	DATE
29.	COMMENTS	VARCHAR2(255)
30.	MMS_COMPANY_NUM_FK	VARCHAR2(5)
31.	SURVEY_DATE_FK	DATE
32.	QC_DATE	DATE

4.16 Survey Information

Table Name: SURVEYS

Column Names:

1.	MMS_COMPANY_NUM	VARCHAR2(5)	
2.	SURVEY_DATE	DATE	
3.	BUS_ASC_NAME	VARCHAR2(50)	
4.	LINE_1_ADDRESS	VARCHAR2(50)	
5.	LINE_2_ADDRESS	VARCHAR2(50)	
6.	CITY_NAME	VARCHAR2(50)	
7.	STATE	VARCHAR2(50)	
8.	ZIP_CODE	VARCHAR2(50)	
9.	CONTACT	VARCHAR2(50)	
10.	PHONE	VARCHAR2(50)	
11.	FAX	VARCHAR2(50)	
12.	EMAIL	VARCHAR2(50)	
13.	STATUS	VARCHAR2(1)	DEFAULT 'C'
14.	COMMENTS	VARCHAR2(255)	
15.	LAST_UPDATED	DATE	
16.	LAST_QC	DATE	
17.	LAST_EXPORTED	DATE	
18.	INSTALL_DATE	DATE	
19.	PROGRAM_LAST_RUN	DATE	
20.	PROGRAM_VERSION	VARCHAR2(10)	

4.17 QC Survey Information

Table Name: QC_SURVEYS

Column Names:

1. QC_ID NUMBER(20,0)
2. COMPLEX_ID_NUM VARCHAR2(7)
3. STRUCTURE_NUMBER VARCHAR2(8)
4. QC_LEVEL VARCHAR2(2) DEFAULT 'SU'
5. EQUIP_TYPE VARCHAR2(3)
6. EQUIP_ID VARCHAR2(8)
7. FIELD_ID VARCHAR2(50)
8. QC_DESC VARCHAR2(255)
9. COMMENTS VARCHAR2(255)
10. MMS_COMPANY_NUM_FK VARCHAR2(5)
11. SURVEY_DATE_FK DATE

4.18 Vents

Table Name: VENTS

Column Names:

1. VENT_TYPE VARCHAR2(1) HIGH PRESSURE; LOW PRESSURE
2. EQUIP_ID VARCHAR2(8)
3. EQUIP_TYPE VARCHAR2(3)
4. STATUS VARCHAR2(1)
5. STATUS_EFF_DATE DATE
6. COMMENTS VARCHAR2(255)
7. QC_DATE DATE
8. ST_ID_FK NUMBER(20)
9. STACK_OUTLET_ELEV NUMBER(7,3) ft above msl
10. STACK_ANGLE NUMBER(3) degrees; 0=vert, 90=horiz; 180=down (range 1-180)
11. STACK_INNER_DIAM NUMBER(6,3) inches
12. STACK_EXIT_VEL NUMBER(8,3) ft/s
13. STACK_EXITT NUMBER(7,3) Deg F

14. NUM_VENT_OCCUR NUMBER(4,0) Number of upset vent occurances. For each, track the start date, duration (hrs), peak vent rate (Mscf/day).
15. HRS_OPERATED NUMBER(7,3) hours
16. VOL_VENTED NUMBER(9,3) Mscf
17. CONTROL_TECH VARCHAR2(4) CONDENSER; NONE
18. CONDENSERT NUMBER(7,3) Deg F
19. CONDENSERP NUMBER(8,3) psia
20. CONC_VOC NUMBER(11,3) ppmv
21. CONC_H2S NUMBER(11,4) ppmv
22. VOC_MOL_WGT NUMBER(7,3) lb/lb-mol
23. OTHER_CNT_DEV VARCHAR2(1)
24. OTHER_CNT_DESC VARCHAR2(255)
25. OTHER_CNT_EFFSOX NUMBER(6,3) %
26. OTHER_CNT_EFFNOX NUMBER(6,3) %
27. OTHER_CNT_EFFCO NUMBER(6,3) %
28. OTHER_CNT_EFFVOC NUMBER(6,3) %
29. OTHER_CNT_EFFPM10 NUMBER(6,3) %

4.19 Vent Upsets

Table Name: VENT_UPSETS

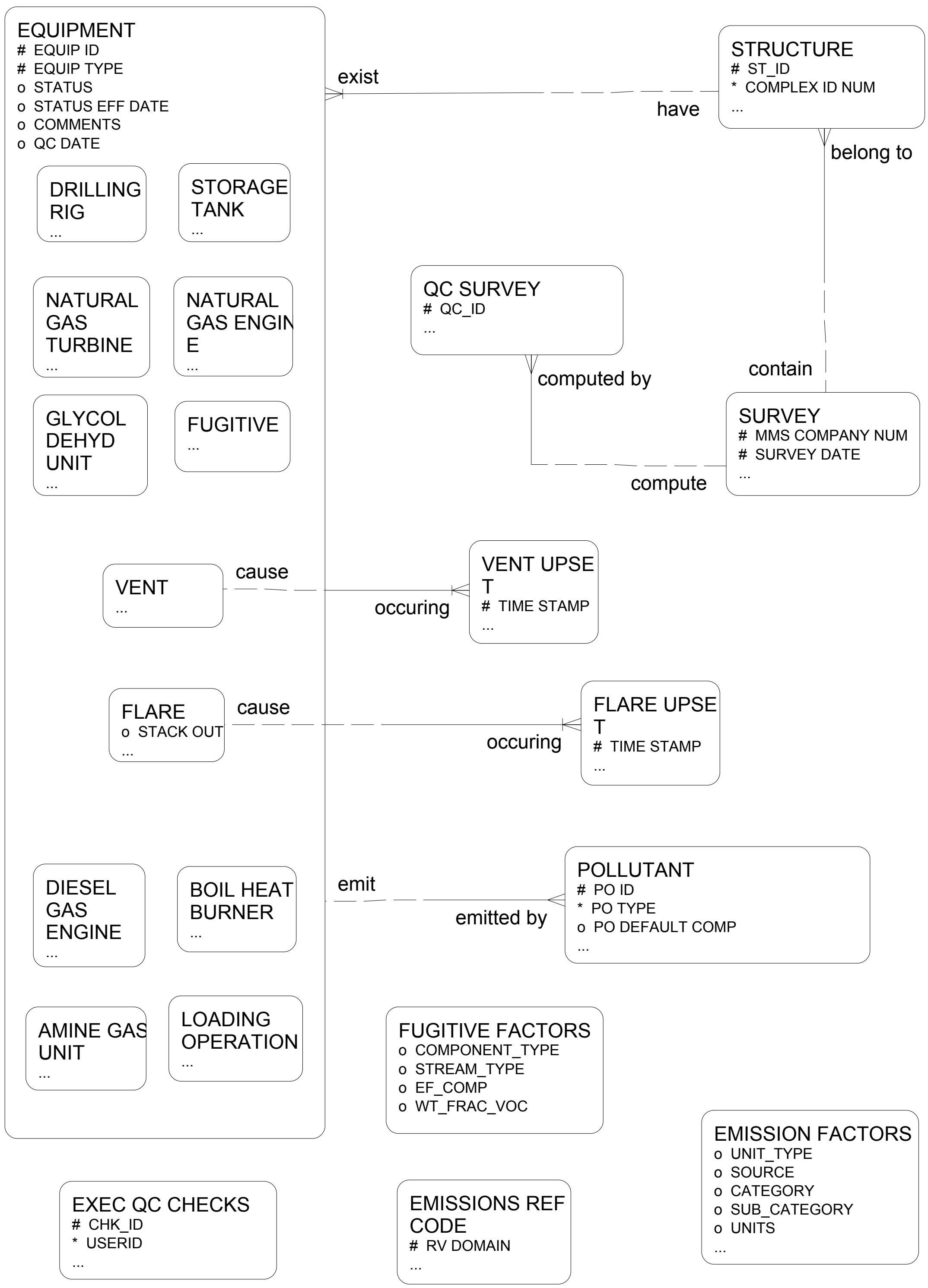
Column Names:

1. TIME_STAMP DATE date/time
2. HRS_OPERATED NUMBER(7,3) hours
3. AVG_FEED NUMBER(9,3) Mscf/hr
4. CONC_H2S NUMBER(11,4) H2S Concentration (ppmv)
5. EXIT_TEMP NUMBER(9,3) Deg F
6. COMMENTS VARCHAR2(255)
7. ST_ID_FK NUMBER(20)
8. EQUIP_ID_FK VARCHAR2(8)

9. EQUIP_TYPE_FK VARCHAR2(3)

5 Entity-Relationship Diagram (ERD)

5.1 ERD – Permanent Tables



5.2 ERD – Temporary Tables

EQVENORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EQNGTORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EQGLYORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EQFLAORC
- o USERID
- o MONTH
- o YEAR
- ...

EQFUGORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EQVEN2ORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EQNGEORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- ...

EQSTORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EQQCORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EQAMIORC
- o USERID
- o MONTH
- o YEAR
- ...

EQLOAORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EQFLA2ORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- o EQUIPID
- o TIMESTAMP
- ...

EQSTOORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EQDRIORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- o EQUIPID
- o HRSOPERATED
- ...

EQUSRORC
- o USERID
- o COMPANY
- o ADDRESS1
- o ADDRESS2
- o CITY
- ...

EM LOG
- o RECNUM
- o NEW_LINE

EQBOIORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EQSVORC
- o USERID
- o MONTH
- o YEAR
- o COMPANY
- o ADDRESS1
- ...

EQDIEORC
- o USERID
- o MONTH
- o YEAR
- o CMPLXID
- o STRUCTID
- ...

EM ERROR LOG
- o FILE_PATH
- o FILE_NAME
- o ERR_TYPE

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Minerals Revenue Management** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.